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

March 21, 2025

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: Application for Capital Expenditures for the Purchase and Installation of Bay d'Espoir Unit 8 and Avalon Combustion Turbine – Redacted

Please find enclosed Newfoundland and Labrador Hydro's ("Hydro") application for the capital expenditures related to the purchase and installation of Bay d'Espoir Unit 8 ("BDE Unit 8") and Avalon Combustion Turbine ("Avalon CT") ("2025 Build Application"), along with a customer focused summary that is intended to assist the public with understanding and awareness of what is requested in the 2025 Build Application and the reasons for the application.

Through Hydro's ongoing Reliability and Resource Adequacy Study Review proceeding *("RRA Study Review")*, Hydro identified the need for additional generation to meet load growth and system reliability requirements. In the most recent update, the 2024 Resource Adequacy Plan, Hydro focused on the production of an Island Interconnected System Expansion Plan that satisfied both capacity and energy requirements. The 2024 Resource Adequacy Plan assessed the integration of new assets, system reliability, and the effects of electrification and decarbonization across various scenarios. The analysis highlights that, in all modeled scenarios, urgent investment in increased electrical supply is essential and justified to maintain a reliable power supply for customers on the Island.

In the 2024 Resource Adequacy Plan, Hydro recommended the Minimum Investment Required Expansion Plan that meets reliability while balancing cost and environmental considerations. The preferred, least-cost, environmentally responsible resource options under this recommendation are BDE Unit 8 and the Avalon CT.

The 2025 Build Application is structured as follows:

- An Overview document that provides a summary of Hydro's justification for the projects proposed in the 2025 Build Application is provided as Schedule 1 to the application.
- A Settlement Agreement arising out of the *RRA Study Review* and the review of the 2024 Resource Adequacy Plan is provided as Schedule 2 to the application. The Settlement

Agreement was signed by Hydro, the Consumer Advocate, Newfoundland Power Inc., and the Island Industrial Customer Group, who have agreed that various issues arising regarding the *RRA Study Review* and the 2024 Resource Adequacy Plan have been settled by negotiations between them. These issues are detailed in Attachment 1 to the Settlement Agreement ("Settled Issues").[1]

- Schedule 3 to the application contains an updated Expansion Plan analysis, reflecting an updated 2024 Load Forecast[2] and refined capital estimates for the proposed projects and the other supply stack alternatives. This analysis continues to identify the Avalon CT and BDE Unit 8 as the least-cost options and necessary first steps to meet expected demand.
- The comprehensive evidence packages, included for BDE Unit 8 at Schedule 4 and for the Avalon CT at Schedule 5, provide detailed explanation and evidentiary support for each project. Hydro has requested approval of an Authorized Budget of $1.08 billion for BDE Unit 8, with anticipated completion in 2031 and $891 million for the Avalon CT, with anticipated completion in 2029.

The Settled Issues include agreement that the recommendation to build a new 154 MW unit at Bay d'Espoir and a 150 MW combustion turbine on the Avalon Peninsula, based on the Slow Decarbonization Case described in the 2024 Resource Adequacy Plan, is appropriate as part of the first step in addressing the requirements for additional capacity for the Island Interconnected System and applications for these projects should be filed for evaluation at this time.

The parties agreed that Hydro analyzed an appropriate range of scenarios and sensitivities for the analysis included in the 2024 Resource Adequacy Plan to determine Hydro's recommendations regarding the minimum investment required being Bay d'Espoir Unit 8 and the Avalon CT. They further agreed that the 2023 Load Forecast and the reliability planning analysis outlined in the 2024 Resource Adequacy Plan demonstrate that additional capacity is required for the Island Interconnected System in the period 2031–2034 with the amount of capacity depending on the case and scenario analyzed. The parties agree that the 2024 Resource Adequacy Plan's Reference Case results indicate that approximately 525 MW of capacity is required by 2034. The Minimum Investment Expansion Plan, based on the Slow Decarbonization load forecast results, indicate a minimum of 385 MW of new capacity is required by 2034. Through the Settlement Agreement, the parties recommend that the Board of Commissioners of Public Utilities ("Board") accept their agreement regarding the Settled Issues during the Board's evaluation of the 2025 Build Application, and consent to the admission in the record of matter of all pre-filed testimony, exhibits, and responses to requests for information pertaining to the Settled Issues.

The *RRA Study Review* process, specifically the review of the 2024 Resource Adequacy Plan, enabled the analysis and recommendations for the proposed BDE Unit 8 and an Avalon CT projects to be discussed and dissected by Intervenors and Board staff, as well as their consultants and legal counsel. Hydro's application and the evidence contained therein has evolved from the analysis completed in that proceeding, in particular the filings associated with the 2024 Resource Adequacy Plan.

While the 2025 Build Application is comprehensive and detailed and, Hydro believes, fully supports the requests to proceed with BDE Unit 8 and the Avalon CT; and while the Settlement Agreement confirms the Intervenors' agreement with certain underlying principles related to the 2025 Build Application specifically, Hydro believes that the 2024 Resource Adequacy Plan and related aspects of the *RRA Study*

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[1] The Labrador Interconnected Group would be signing only to the extent to reflect agreement to item 1 in the Settled Issues List that forms part of the Settlement Agreement. That item does not have implications for the proposals in the attached application; the fully executed Settlement Agreement will be filed once received.

[2] The 2024 Load Forecast is provided as Appendix A to Schedule 3 of this application.

Review record provides fulsome context and additional support for the projects outlined in the 2025 Build Application. Aspects of that record are referenced throughout the attached application; however, to ensure an efficient review of the application Hydro requests that the following aspects of the *RRA Study Review* record be placed on the record of this proceeding:

- 2023 Load Forecast[3]
- 2024 Resource Adequacy Plan[4]
- Requests for Information[5]
  - PUB-NLH-311 to PUB-NLH-340
  - IIC-NLH-009 to IIC-NLH-022
  - NP-NLH-095 to NP-NLH-104
  - CA-NLH-061 to CA-NLH-067
- Technical Conference ("TC") Presentations
  - TC 1 (Load Forecast/Reliability Planning Criteria)[6]
  - TC 2, Day 1 (Existing Generation and Transmission)[7]
  - TC 2, Day 2 (Resource Supply Options)[8]
  - TC 3 (Scenarios and Sensitivities/Modelling Approach and Considerations)[9]
  - TC 4 (Expansion Plan, Insights and Next Steps)[10]
- Reports from the Board's consultant, Bates White
  - Assessment of Newfoundland and Labrador Hydro's 2024 Resource Adequacy Plan[11]
  - Assessment of Newfoundland and Labrador Hydro's Long-Term Load Forecast Report – 2023.[12]

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[3] http://www.pub.nl.ca/applications/NLH2018ReliabilityAdequacy/reports/From%20NLH%20-%202023%20Long-Term%20Load%20Forecast%20Report%20-%202024-03-28.PDF.

[4] http://www.pub.nl.ca/applications/NLH2018ReliabilityAdequacy/correspondence/From%20NLH%20-%202024%20Resource%20Adequacy%20Plan%20-%20REVISION%202%20-%20REDACTED%20-%202024-08-26.PDF.

[5] http://pub.nl.ca/applications/NLH2018ReliabilityAdequacy/responses.php.

[6] http://www.pub.nl.ca/applications/NLH2018ReliabilityAdequacy/reports/From%20NLH%20-%20Presentation%20-%20Technical%20Conference%201%20Load%20Forecast%20-%20Reliability%20Planning%20Criteria%20-%202024-09-17.PDF.

[7] http://www.pub.nl.ca/applications/NLH2018ReliabilityAdequacy/correspondence/From%20NLH%20-%20Presentation%20-%20Technical%20Conference%202%20-%20Issue%203%20-%20Existing%20Generation%20and%20Transmission%20-%202024-10-01.PDF.

[8] http://www.pub.nl.ca/applications/NLH2018ReliabilityAdequacy/correspondence/From%20NLH%20-%20Presentation%20-%20Technical%20Conference%202%20-%20Issue%204%20%20-%20Resource%20Supply%20Options%20-%202024-10-02.PDF.

[9] http://www.pub.nl.ca/applications/NLH2018ReliabilityAdequacy/correspondence/From%20NLH%20-%20Presentation%20-%20Technical%20Conference%203%20-%20Scenarios%20and%20Sensitivities%20-%20Modelling%20Approach%20and%20Considerations%20-%202024-10-16.PDF.

[10] http://www.pub.nl.ca/applications/NLH2018ReliabilityAdequacy/correspondence/From%20NLH%20-%20Presentation%20-%20Technical%20Conference%204%20-%20Expansion%20Plan,%20Insights%20and%20Next%20Steps%20-%202024-10-29.PDF.

[11] http://www.pub.nl.ca/applications/NLH2018ReliabilityAdequacy/reports/Bates%20White%20-%20Expert%20Report%20-%20Assessment%20of%20NLHs%20-%202024%20Resource%20Adequacy%20Plan%20-%202024-08-30.PDF.

[12] http://www.pub.nl.ca/applications/NLH2018ReliabilityAdequacy/reports/Bates%20White%20Load%20Forecast%20Review%20Report%20-%20Final%202024.07.25.pdf.

As outlined in the 2024 Resource Adequacy Plan, in every scenario studied, additional generation resources are required within the next ten years. Considering the current capacity constraints on the Island Interconnected System, the need to retire aging thermal assets, and the timeframe to construct new assets, it is imperative to action new resource options now to maintain a reliable electricity system.

The proposed capital expenditures detailed in the 2025 Build Application are necessary to ensure that Hydro can continue to provide service that is safe and adequate, and just and reasonable, as required by Section 37 of the *Public Utilities Act*.

The planning, construction, and integration of these new generating resources will take years. Project estimates are time sensitive and supply chain pressures continue to increase; therefore, any delay impacting project execution increases the risk of higher costs to ratepayers, underscoring the need for expedient action. Efficient and expedient review and decisions are critical.

The 2025 Build Application contains commercially sensitive information that, if made public, would undermine Hydro's ability to obtain goods and services at the lowest possible cost and therefore negatively impact Hydro's customers. A version in which this information has been redacted is enclosed. The Board has been provided with a complete copy as well as a copy of the redacted version. Hydro requests that this information be kept confidential, not be made publicly available, and that the Board use the redacted version for posting to its website.

Should you have any questions, please contact the undersigned.

Yours truly,

NEWFOUNDLAND AND LABRADOR HYDRO

SWalsh

Shirley A. Walsh
Senior Legal Counsel, Regulatory
SAW/kd

Encl.

ecc:

Board of Commissioners of Public Utilities
Jacqui H. Glynn
Board General

Island Industrial Customer Group
Denis J. Fleming, Cox & Palmer
Glen S. Seaborn, 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.
Douglas W. Wright
Regulatory Email

2025 Build Application

Bay d'Espoir Unit 8 and Avalon Combustion Turbine

March 21, 2025

An application to the Board of Commissioners of Public Utilities

List of Contents

The components of the 2025 Build Application include:

POWER THE PROVINCE

BUILDING A FUTURE WITH SAFE, LEAST-COST, AND RELIABLE POWER SOLUTIONS

THE POWER OF PLANNING

We're planning for the future and working hard to power the province with safe, reliable electricity at the lowest possible cost for our customers. It's something we all need—and we will need more. Our customers have been clear. The cost of living, including electricity rates, is a concern—they prioritize lower electricity costs before investment in increased reliability or renewable technologies.

With lessons of the past in mind, and with the oversight of the Public Utilities Board, we are moving forward with what absolutely and urgently must be done to support system reliability and have supply in place to meet load growth.

TIME TO BUILD

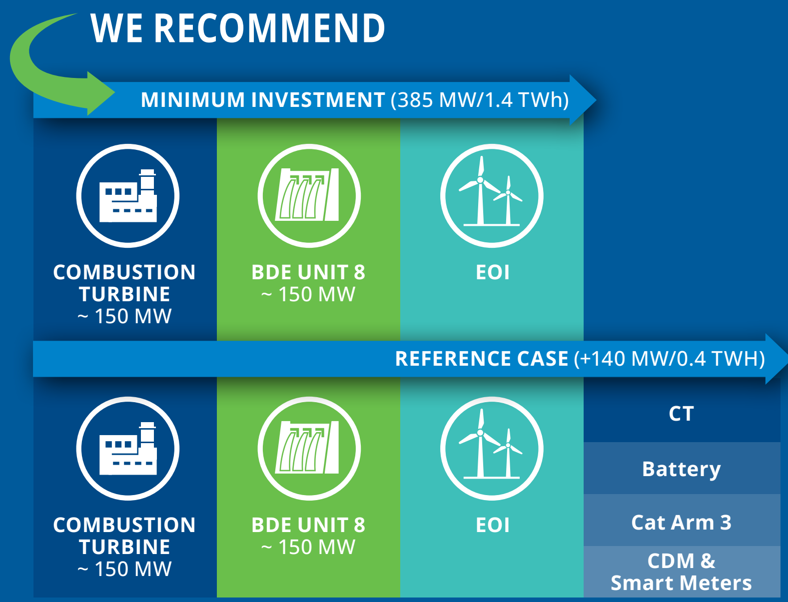
In 2024, Hydro filed our 2024 Resource Adequacy Plan (2024 Plan) with the Public Utilities Board. This was a continuation of our planning process, which addresses our long-term approach to providing continued lowest cost, reliable service for our customers.

The 2024 Plan assessed the integration of new assets, system reliability, and the effects of electrification and decarbonization across various scenarios.

Our analysis demonstrated that, in all modeled scenarios, urgent investment is required to ensure continued reliability of our electrical system and to prepare for load growth.

As a first step, and in recognition that our customers are counting on us to invest wisely and prudently, we recommended a Minimum Investment Required Expansion Plan. The plan proposed an additional 150 megawatt (MW) unit at the Bay d'Espoir Hydroelectric Generating Facility ("BDE Unit 8") and a new 150 MW combustion turbine with renewable fuel capabilities located on the Avalon Peninsula ("Avalon CT") as the preferred, least-cost, environmentally responsible resource options to address our capacity needs. Our plan also identified wind energy to meet our energy needs.

We are also working to ensure that plans are in place for scenarios with more aggressive load growth. While such cases may require additional supply, BDE Unit 8, Avalon CT, and wind energy represent the minimum investment required across all scenarios.



We have now gathered all the evidence required to support our submission of the 2025 Build Application to the Public Utilities Board for these capacity-focused solutions.

Wind does not form part of Hydro's 2025 Build Application. Rather, we will continue our ongoing analysis and will proceed with an Expression of Interest (EOI) to identify potential wind developers and development opportunities later this year. As wind requirements are confirmed, we will issue a request for proposals (RFP).

This summary presents an overview of the application.

The full application with documentation is available at PowerTheProvince.ca.

HOW MUCH DOES THE ISLAND NEED?

The 2024 Resource Plan determined we need capacity and energy.

Capacity is the maximum amount our 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.

In 2024, Island demand reached 1691 MW and is expected to grow to 1928 MW by 2035—a 14% increase. We need to add capacity to meet this demand.

In 2024, we used 7.8 TWh of energy on the Island and use is expected to grow to 9.0 TWh by 2035—that's 17% more energy.

HYDRO'S 2025 BUILD APPLICATION IS THE FIRST STEP TO ADDRESSING OUR CAPACITY NEEDS.

LISTENING TO OUR CUSTOMERS

Hydro values the perspectives of everyone who may be impacted by decisions about the delivery of safe, reliable, environmentally responsible electricity. Through a province-wide digital engagement, we engaged our customers to gather opinions about our next big decisions. Customers were very clear. The cost of living, including electricity rates, is a concern and they have a strong preference to prioritize lower electricity costs before investment in increased reliability or renewable technologies.

With this is mind, Hydro is moving forward with what absolutely and urgently must be done to support system reliability and have supply in place to meet load growth – the Avalon CT and BDE Unit 8. These proposed projects continue to be the least-cost options to provide reliable, electricity in an environmentally responsible manner.

We are also engaging and sharing information with the public and other interested groups as we plan these projects. Through various digital, phone, and in person meetings, we have engaged elected officials and senior staff from the communities that will be home to the new projects. We have also held public information sessions for area residents, and have met and shared information with other interested groups.

As we move forward, Hydro is committed to ongoing engagement and keeping the public, interested groups, and our own employees informed. We will continue to gather input as we advance though Environmental Assessment, Public Utilities Board application processes, planning, and construction.

APPROACH TO MAJOR PROJECTS

Recognizing the criticality of project oversight in the success of major projects, Hydro has taken measures to ensure the effective planning, execution, and delivery of major projects, including the two in this application. Our ability to execute these projects is supported by highly qualified project teams and a governance framework that reflects lessons learned from past projects, industry standards and good utility practice.

Hydro has built a team of experienced, subject matter experts from across the organization and representing a variety of professional and corporate services.

This team will be supplemented by external experts as necessary, and with oversight from our Executive and Board of Directors. We are leveraging insights gained from Hydro's Internal Audit & Advisory Services group, the Muskrat Falls Inquiry, other utilities such as members of the Canadian Electric Utility Project Management Network and lessons learned from previous projects. Further, our investment decisions will be tested and approved as part of a public, transparent regulatory process through the Public Utilities Board.

We are working closely with the Government of Newfoundland and Labrador (GNL) to ensure customers in this province continue to pay some of lowest electricity rates in Canada.

While GNL's Rate Mitigation Plan provides for predictability and stability of Hydro's rates out to 2030, both GNL and Hydro have expressed a commitment to continued rate mitigation post 2030.

BUILDING FOR OUR FUTURE

The Island Interconnected System is currently capacity-constrained. Given the timeframe to construct new assets, it is imperative to action new resource options now. BDE Unit 8 and the Avalon CT are the first steps to reliably serving customers on the Island as system demand grows in the coming decade. By focusing on foundational capacity supply options in the minimum investment case, we are addressing the immediate need to build and bring additional supply options online to meet the growing demand for electricity in Newfoundland and Labrador. In doing so, we also set the stage for the eventual retirement of Holyrood's thermal generating units.

While many supply options were explored, these two supply solutions were the least-cost, technically viable and reliable options for the Island Interconnected System and are supported by data, experience, expertise, and customer feedback.

Our 2025 Build Application includes all the evidence to support this decision, including an updated 2024 load forecast and refined cost estimates for both BDE Unit 8 and Avalon CT.

We need to get started so we can see both new assets brought online by 2031, as well as manage project costs.

(see project timelines on the next page)

WHY A COMBUSTION TURBINE ON THE AVALON?

The 150 MW combustion turbine facility, which will be able to use renewable fuels, will serve as an important backup power source to support system stability and energy reliability during periods when demand for electricity is at its highest. It will primarily be used when needed to help meet peak demand—this is how such assets are used across Canada today.

Several locations were considered. Evaluation criteria identified that building on the existing Holyrood site is best to meet future demand at the lowest cost. Additionally, it allows for connection on the Avalon Peninsula, where demand for electricity is the highest. This unit can be connected to existing transmission infrastructure and represents the lowest capital cost.

In December 2024, the Government of Canada finalized the Clean Electricity Regulations ("CER"). These regulations were a key consideration in Hydro's evaluation of potential new sources of generation during the 2024 Resource Adequacy Plan. The Avalon CT would be compliant with the CER, based on its use as a peaking unit or for providing backup generation in the event of high demand periods or during contingency events.

PROPOSED BUDGET ~$891M

WHY AN ADDITIONAL UNIT AT BAY D'ESPOIR?

The Bay d'Espoir generating station has been a central part of our province's electricity system for more than 50 years, and it will continue operation well into the future.

Analysis has determined that adding an eighth generating unit at the Bay d'Espoir facility will help meet growing demand for electricity, while supporting the reliability of service for customers. The addition of a new 150 MW hydroelectric unit represents the next investment required to serve customer demand now and into the future. The Bay d'Espoir facility was originally designed for the eventual addition of an eighth unit. Now that our system needs additional capacity—that future is here.

Investment in BDE Unit 8, combined with the Avalon CT, also supports the eventual retirement of Holyrood, which is currently being kept online to support the reliable operation of the power system.

PROPOSED BUDGET ~$1.08B

Proposed budgets for the new projects were determined using the confidence levels recommended by the Muskrat Falls Inquiry.

PROGRESS TO DATE

2018

- Initial Reliability and Resource Adequacy Study (RRA) filed with Public Utilities Board, with updates filed in 2019, 2021, and 2022

2024

- 2024 Resource Adequacy Plan
- Front End Engineering Design completed
- Early engagement with key parties

2025

- Early execution work planning
- Public engagement ongoing
- Build application submitted

MILESTONES*

AVALON COMBUSTION TURBINE

BDE UNIT 8

WIND

2025

- Environmental assessment
- Regulatory review
- Early site preparation
- Procurement begins
- Detailed engineering design
- Detailed construction planning

2026

- On site construction begins

2028

- On site construction begins

2029

- Facilities completed
- Project commissioning
- Ready for operation

2030

- Powerhouse completed

2031

- Project commissioning
- Ready for operation

2030 – 2031 – 2033

Hydro expects to bring on the first wave of new energy in 2030, with incremental amounts as required in subsequent years.

**Schedule reflects regulatory approvals in 2025*

IN THE MATTER OF the *Electrical Power Control Act, 1994*, SNL 1994, Chapter E-5.1 ("*EPCA*") and the *Public Utilities Act*, RSNL 1990, Chapter P-47 ("*Act*"), and regulations thereunder; and

IN THE MATTER OF an application by Newfoundland and Labrador Hydro ("Hydro") for approval of capital expenditures for the purchase, construction, and installation of Unit 8 at the Bay d'Espoir Hydroelectric Generating Facility ("Bay d'Espoir") and a combustion turbine ("CT") located on the Avalon Peninsula.

To: The Board of Commissioners of Public Utilities ("Board")

THE APPLICATION OF HYDRO STATES THAT:

A. Background

1. Hydro is a corporation continued and existing under the *Hydro Corporation Act, 2024*, is a public utility within the meaning of the *Act,* and is subject to the provisions of the *EPCA.*

2. Through substantial analysis completed within the *Reliability and Resource Adequacy Study Review* proceeding (*"RRA Study Review"*), and in particular as pertaining to the 2024 Resource Adequacy Plan[1] as part of the *RRA Study Review*, Hydro determined that a minimum investment is necessary to ensure Hydro can continue to provide service that is safe and adequate, and just and reasonable, as required by Section 37 of the *Act*.

3. The 2024 Resource Adequacy Plan assessed the integration of new assets, system reliability, and the effects of electrification and decarbonization across various scenarios. The analysis highlighted that, in all modelled scenarios, urgent investment in increased electrical supply is essential and justified to maintain a reliable power supply for customers.

[1] "2024 Resource Adequacy Plan – An Update to the Reliability and Resource Adequacy Study," Newfoundland and Labrador Hydro, rev. August 26, 2024 (originally filed July 9, 2024).
http://www.pub.nl.ca/applications/NLH2018ReliabilityAdequacy/correspondence/From%20NLH%20-%202024%20Resource%20Adequacy%20Plan%20-%20REVISION%202%20-%20REDACTED%20-%202024-08-26.PDF.

4. In Hydro's updated Reference Case Expansion Plan scenario (the scenario most likely to occur), Hydro's analysis determined that approximately 525 MW of new generation is required by 2034 to address the additional Island demand and to allow for the retirement of aging thermal assets, including the Holyrood Thermal Generating Station ("Holyrood TGS").

5. The Minimum Investment Required Expansion Plan, as described in the 2024 Resource Adequacy Plan and the enclosed application, is based on a high level of Labrador-Island Link reliability and the lowest load growth (2024 Slow Decarbonization forecast) that can be reasonably anticipated for the Island Interconnected System. The Minimum Investment Required adds 385 MW of new capacity on the Island Interconnected System.

6. Hydro's evidence, as enclosed with this application, supports the construction of two new capacity resources, specifically:

   (i) An additional 150 MW unit at Bay d'Espoir ("BDE Unit 8"); and

   (ii) A new approximately 150 MW CT with renewable fuel capabilities located on the Avalon Peninsula ("Avalon CT") (collectively, the "2025 Build Application").

7. The parties to the *RRA Study Review*, more specifically Hydro, the Consumer Advocate, Newfoundland Power Inc., and the Island Industrial Customers Group, came to an agreement on certain facts and principles within that proceeding ("Settled Issues") that have implications for the 2025 Build Application. The Settlement Agreement is attached to this application as Schedule 2.[2]

8. Through the Settlement Agreement, the parties recommend that the Board accept their agreement regarding the Settled Issues during the Board's evaluation of the 2025 Build Application, and the parties' further consent to the admission in the record of matter of all pre-filed testimony, exhibits, and responses to requests for information pertaining to the Settled Issues.

[2] The Labrador Interconnected Group would be signing only to the extent to reflect agreement to item 1 in the Settled Issues List that forms part of the Settlement Agreement. That item does not have implications for the proposals in the attached application; the fully executed Settlement Agreement will be filed once received.

B. Application

9. Bay d'Espoir is located on the south coast of Newfoundland and Labrador and is the largest hydroelectric generating facility in the Island Interconnected System. Bay d'Espoir currently provides 613 MW of electrical capacity and 2,560 GWh of energy annually via seven existing units and includes a reservoir, a spillway, and two powerhouses.

10. The proposed BDE Unit 8 will supplement the existing Bay d'Espoir Hydroelectric Development, via the use of the existing reservoir and will be located with Powerhouse 2. BDE Unit 8 is expected to have a capacity of approximately 150 MW, which will help meet the system's requirement for additional capacity. There is no appreciable expected additional energy from this addition.

11. The Avalon CT will supplement system capacity by adding a new multi-unit 150 MW generating facility that will provide peaking power support and standby generation and enable reduced generation from the Holyrood TGS. The location identified for the Avalon CT is the Holyrood TGS site.

12. The 2025 Build Application requests approval of a total overall Authorized Budget of $1.97 billion for both of the necessary proposed projects, inclusive of the planned project budgets and a management reserve. In acting on recommendations from the Muskrat Falls Inquiry and consistent with best practices in major projects, Hydro established a Management Reserve to assist with the management of strategic risks. The Management Reserve is further discussed in Section 5.4 of Schedule 1.

13. The total requested Authorized Budget for BDE Unit 8 is $1.08 billion, with anticipated completion in 2031. The capital cost estimates, planned project budgets which include interest during construction and escalation, and the management reserve for each project are described in Schedule 4 and Appendix A thereto.

14. The total requested Authorized Budget for the Avalon CT is $891 million with anticipated completion in late 2029. The capital cost estimates, planned project budgets which include interest during construction and escalation, and the management reserve for each project are described in Schedule 5 and Appendix B thereto.

15. Schedules 1 to 5 to this application are the 2025 Build Application Overview, Settlement Agreement, Expansion Plan Update, BDE Unit 8 Project Evidence, and Avalon CT Project Evidence.

16. Schedule 1: The 2025 Build Application Overview provides:

a) The background to the 2025 Build Application;

b) A summary of Hydro's Expansion Plan Update;

c) A summary of the 2025 Build Application;

d) A discussion of the development of the proposed projects;

e) A synopsis of the BDE Unit 8 evidence;

f) A synopsis of the Avalon CT evidence;

g) A description of Hydro's organizational readiness, including Hydro's Major Projects Governance Framework and execution capability; and

h) A customer rate impact analysis.

17. Schedule 2: Settlement Agreement provides a copy of the Settlement Agreement entered into between Hydro and the parties to the *RRA Study Review* which requests that the Board accept the settlement in its review of the 2025 Build Application.

18. Schedule 3: Expansion Plan Update provides an update to the Expansion Plan Hydro had completed in the *RRA Study Review* to incorporate the latest available information, including an updated load forecast (Schedule 3, Appendix A).

19. Schedule 4: BDE Unit 8 Project Evidence provides detailed evidence in support of BDE Unit 8, including the Basis of Estimate and Basis of Schedule (Schedule 4, Attachments 1 and 2, respectively).

20. Schedule 5: Avalon CT Project Evidence provides detailed evidence in support of Avalon CT, including the Basis of Estimate and Basis of Schedule (Schedule 5, Attachments 1 and 2, respectively).

C. Reason for Approval

21. The proposed capital expenditures for BDE Unit 8 and the Avalon CT as set out in the 2025 Build Application are necessary to allow Hydro to continue to provide to its customers service and facilities that are reasonably safe and adequate, and just and reasonable, as required by Section 37 of the *Act*.

D. Newfoundland and Labrador Hydro's Request

22. Hydro requests that the Board make an Order as follows:

(i) Approving the requested Authorized Budget for the BDE Unit 8 in the amount of $1.08 billion as set out in Appendix A of Schedule 4, pursuant to Section 41(1) of the *Act*; and

(ii) Approving the requested Authorized Budget for the Avalon CT in the amount of $891 million as set out in Appendix B of Schedule 5, pursuant to Section 41(1) of the *Act*.

E. Communications

23. Communications with respect to this Application should be forwarded to Shirley A. Walsh, Senior Legal Counsel, Regulatory for Hydro.

DATED at St. John's in the province of Newfoundland and Labrador on this 21st day of March 2025.

NEWFOUNDLAND AND LABRADOR HYDRO

SWalsh

Shirley A. Walsh
Counsel for the Applicant
Newfoundland and Labrador Hydro
500 Columbus Drive, P.O. Box 12400
St. John's, NL A1B 4K7
Telephone: (709) 685-4973

Schedule 1

Schedule 1

Application Overview

Bay d'Espoir Unit 8 and Avalon Combustion Turbine

Contents

List of Appendices

List of Attachments

Attachment 2: "Hydrology and Feasibility Study for Potential Bay d'Espoir Hydroelectric Generating Unit No. 8 – Addendum Report," Hatch Limited.

1.0 Highlights

After thorough consideration of the recommendations within the 2024 Resource Adequacy Plan[1] as part of the *Reliability and Resource Adequacy Study Review* proceeding (*"RRA Study Review"*), Newfoundland and Labrador Hydro's ("Hydro") submits its supplemental capital application for the construction of two new capacity resources:

(i) An additional 150 MW[2] unit at the Bay d'Espoir Hydroelectric Generating Facility ("BDE Unit 8"); and,

(ii) A new approximately 150 MW combustion turbine ("CT")[3] with renewable fuel capabilities located on the Avalon Peninsula ("Avalon CT"), (collectively, the "2025 Build Application").

In this overview document, Hydro will provide a summary of its justification for the 2025 Build Application, which includes:

- Hydro's recommendations supported by a Settlement Agreement provided as Schedule 2 to this application, built upon the extensive regulatory record of the *RRA Study Review*, dating back to the first installment in 2018;
- Hydro's risk-mitigating approach via the Minimum Investment Required Expansion Plan;
- How Hydro's proposals align with customer feedback on rates, reliability and clean energy received through the 2024 customer engagement;
- Additional analysis based on updated load forecast scenarios and cost estimates which continue to identify BDE Unit 8 and the Avalon CT as the least-cost options and necessary first steps to meet expected demand;
- Overall project budgets, which include a reserve to manage strategic risks, consistent with the findings of the Muskrat Falls Inquiry and current best practices within major projects;

[1] "2024 Resource Adequacy Plan – An Update to the Reliability and Resource Adequacy Study," Newfoundland and Labrador Hydro, rev. August 26, 2024 (originally filed July 9, 2024) ("2024 Resource Adequacy Plan").
[2] All references to capacity made throughout this schedule are in nominal terms.
[3] 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.

- Improvements in governance, cost estimation, and oversight for both projects based on recommendations from the Muskrat Falls Inquiry and current best practices within major projects;
- Comprehensive evidence packages supporting Hydro's project schedule and costs, led by a Major Projects Team capable of executing complex, large-scale projects; and
- How timely decision-making remains the most effective method to ensure projects are delivered on budget and on schedule.

2.0 Progress and the Path Forward

The 2025 Build Application represents a culmination of the significant work completed by Hydro to apply for the resource options identified through the *RRA Study Review*.[4] Hydro has been analyzing the island system for the timing and magnitude of the next resource options since 2018. The major steps advanced over the last seven years include:

- Confirmation and development of planning criteria and forecast/updating of customers' future electricity needs;
- Engaging customers to determine preferences on the balance of cost, reliability and renewable energy, among other factors;
- Determination of least-cost, technically viable supply solutions to meet planning criteria and demand; and
- Preliminary engineering and associated costing for best supply solutions that meet planning criteria and demand, as well as the development of a capital application for supply solutions.

The following sections provide more detail on the major filings that describe the significant steps taken to date.

2.1 History of the *RRA Study Review*

Through the *RRA Study Review*, Hydro identified the need for additional generation to meet load growth and system reliability requirements. Hydro completed its first Reliability and Resource Adequacy Study

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

in 2018, which outlines Hydro's system planning criteria and addresses Hydro's resource planning process, providing an in-depth analysis of how much electricity customers will need in future. That study was filed with the Board of Commissioners of Public Utilities ("Board" or "Regulator") the same year.

Since the initial filing in 2018, followed by subsequent filings in 2019, 2021, 2022, and most recently in the 2024 Resource Adequacy Plan, the Board and intervening parties were engaged to allow for a thorough review of the electricity sector landscape, associated study assumptions, outcomes and recommendations. The filings addressed Hydro's long-term approach to providing continued reliable service for our customers. In particular, Hydro's 2022 filing layered additional planning criteria for the reliability of the Labrador-Island Link ("LIL"), and addressed the long-term operation of the Holyrood Thermal Generating Station ("Holyrood TGS"), considering which assets should be maintained. The 2022 study also determined that new assets were required to meet future demand.

The *RRA Study Review* encompassed numerous supporting technical reports and studies, including independent reviews conducted by external consultants. Since the November 2022 filing alone, Hydro presented and answered detailed questions at 5 technical conferences, and submitted in excess of 200 requests for information and more than 12 reports to further substantiate the current justification for supply needs.

Throughout the *RRA Study Review*, and in line with Hydro's legislated 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

The *Electrical Power Control Act, 1994,* mandates as the provinces policy that power be delivered to consumers in the province at the lowest possible cost, in an environmentally responsible manner, consistent with reliable service. The utilities, the Board, and the parties to applications relating to the service of customers are required to work to meet this mandate. With this application, in line with its legislated responsibility to ensure adequate supply and reliable service for the people of the province, Hydro is advancing the necessary actions to mitigate the risk of customer outages due to insufficient supply of reliable electricity. As outlined in the 2024 Resource Adequacy Plan, in every scenario studied, additional generation resources are required within the next ten years.[5] It is imperative to action new resource options now to maintain a reliable electricity system, as the Island Interconnected System is currently capacity-constrained, there is a need to retire aging thermal assets, and there is an extensive timeframe required to construct new assets.

2.2 2024 Resource Adequacy Plan

In the most recent update, Hydro focused on the production of an Island Interconnected System Expansion Plan that satisfied both capacity and energy requirements. New requests for large amounts of electricity in Labrador can involve both transmission and generation supply investments. Industrial load is growing in Labrador but the specific supply requirements and system impact are still under examination with interested parties. Given the magnitude of electricity requests, further study is required followed by an iterative process with interested parties before final decisions are made on actual needs in Labrador. Therefore, additional generation for the Labrador Interconnected System was not contemplated within Hydro's 2024 Resource Adequacy Plan.

The 2024 Resource Adequacy Plan assessed the integration of new assets, system reliability, and the effects of electrification and decarbonization across various scenarios.[6] The analysis highlights that, in all modeled scenarios, urgent investment in increased electrical supply is essential and justified to maintain a reliable power supply for customers on the island. In the Reference Case Expansion Plan scenario (the scenario most likely to occur), Hydro's analysis determined that approximately 525 MW of new generation is required by 2034 to address the additional Island demand and to allow for the retirement of aging thermal assets, including the Holyrood TGS. The requirement for additional on-Island capacity is

[5] Please refer to the 2024 Resource Adequacy Plan, app. C.
[6] Please refer to the 2024 Resource Adequacy Plan, 2024 Resource Plan Overview, Table 2.

driven by a variety of factors, including load growth, the retirement of aging assets, and reliability, including the performance of the LIL.

Recognizing the uncertainties that remain for each of the aforementioned drivers, Hydro's strategy in the 2024 Resource Adequacy Plan was 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 and Slow Decarbonization load forecast. Hydro recognizes that this Expansion Plan does not meet the reliability requirements of the Reference Case. However, it does identify resource options that are common to all scenarios considered and should be immediately pursued for advancement through the regulatory process.

As a first step, Hydro recommended[7] BDE Unit 8, along with the Avalon CT as the preferred, least-cost, environmentally responsible resource options. These options also bring a diversity of supply, further reinforcing reliable capacity to the system. The need for additional resources, even in the Minimum Investment Required, is substantial. Hydro will continue to study additional requirements beyond what is proposed in the Minimum Investment Required Expansion Plan and will be recommending solutions as required in the upcoming 2026 Resource Adequacy Plan.

BDE Unit 8 and the Avalon CT are the technically viable, reliable options for the Island Interconnected System and are supported by data, experience, expertise and customer feedback. Throughout the *RRA Study Review*, Hydro provided significant analysis to support these decisions. In addition to BDE Unit 8 and the Avalon CT, the 2024 Resource Adequacy Plan considered many different generation options to meet anticipated system load growth and reliability expectations. These included hydroelectric generation at existing hydro sites as well as greenfield locations, CTs that can use renewable fuels, wind, battery energy storage systems, solar, and transmission requirements. Hydro will continue to evaluate traditional and emerging solutions for its next and future iterations of resource planning.

Subsequent to filing its 2024 Resource Adequacy Plan, Hydro and its experts participated in a series of technical conferences in the fall of 2024 with the Board staff and intervening parties, along with their experts. These technical conferences provided an opportunity for fulsome discussion and enhanced understanding of Hydro's *RRA Study Review* and Expansion Plans. As a result of these proceedings,

[7] Please refer to the 2024 Resource Adequacy Plan, app. C.

Hydro and the Intervenors gained consensus on a number of issues ("Settled Issues") described in a Settlement Agreement provided as Schedule 2 to this application. In the Settlement Agreement, Hydro, the Consumer Advocate, Newfoundland Power Inc. ("Newfoundland Power"), and the Island Industrial Customer Group have agreed that various issues arising within the *RRA Study Review* and the 2024 Resource Adequacy Plan have been settled through negotiations. The Settled Issues include agreement that the recommendation to build a new 150 MW unit at Bay d'Espoir and a 150 MW CT on the Avalon Peninsula, which is based on the Slow Decarbonization Case,[8] is appropriate as part of the first step in addressing the requirements for additional capacity for the Island Interconnected System and applications for these projects should be filed for evaluation at this time.[9]

The parties agreed that Hydro analyzed an appropriate range of scenarios and sensitivities for the analysis included in the 2024 Resource Adequacy Plan to determine Hydro's recommendations regarding the minimum investment required being BDE Unit 8 and the Avalon CT; they further agreed that the 2023 Load Forecast and the reliability planning analysis outlined in the 2024 Resource Adequacy Plan demonstrate that additional capacity is required for the Island Interconnected System in the period 2031–2034 with the amount of capacity depending on the case and scenario analyzed. The Reference Case results indicate that approximately 525 MW of capacity is required by 2034. The Minimum Investment Required Expansion Plan, which is based on the Slow Decarbonization load forecast results, indicate a minimum of 385 MW of new capacity is required by 2034.

Considering the timeframe to engineer, procure, construct and commission new assets in the current environment within the electricity industry, timely approvals to proceed are necessary.

The proceeding for the 2024 Resource Adequacy Plan is an example of how collaboration and open communication amongst all regulatory stakeholders can facilitate an efficient, thorough and diligent regulatory process while expediting decision-making, ultimately enabling cost savings for customers.

[8] For further information, please refer to Hydro's 2024 Load Forecast Report provided as Appendix A to Schedule 3 of this application.

[9] The Labrador Interconnected Group would be signing only to the extent to reflect agreement to item 1 in the Settled Issues List that forms part of the Settlement Agreement. That item does not have implications for the proposals in the attached application; the fully executed Settlement Agreement will be filed once received.

Customers have been very clear. The cost of living, including electricity rates, is a concern, and that is why the options presented in the 2025 Build Application are based on the Minimum Investment Required scenario to meet the imminent needs of the system.

Inaction and failing to advance solutions to maintain system reliability present significant risks; however, overbuilding risks burdening ratepayers with unnecessary costs. To mitigate that risk, Hydro is moving forward with the Minimum Investment Required—what absolutely and urgently must be done to support system reliability and have supply in place to meet load growth.

By proceeding on the basis of the Minimum Investment Required scenario, Hydro is also advancing the first steps of the Reference Case Expansion Plan, as shown in Figure 2.

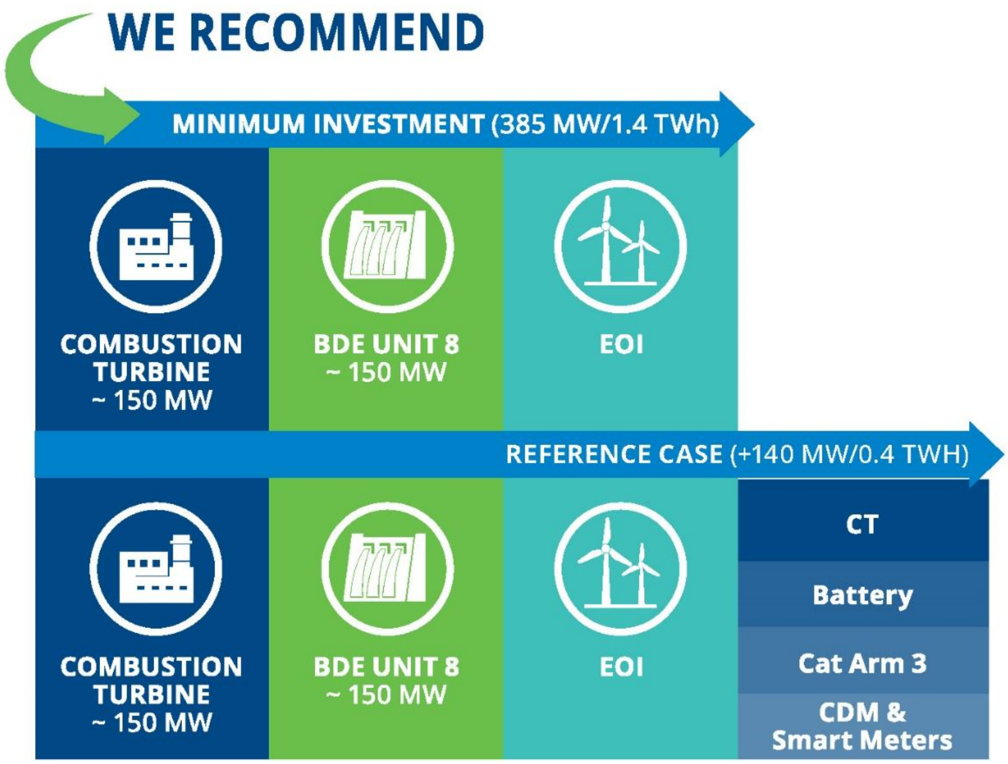


Figure 2: Minimum Investment Required and Reference Case Requirements[10]

[10] Figure 2 reflects the updated analysis as provided in Schedule 3 of this application.

The supply gap between the Minimum Investment Required and the Reference Case is incremental – it does not result in a different recommendation than the initial investment decisions of BDE Unit 8 and an Avalon CT.

Additional resources and further requirements would be necessary in all other scenarios (Reference Case and also cases that model even higher levels of electrification) to accommodate the evolving energy landscape. However, it is important to note that for the other scenarios analyzed, the first resources required in those plans are the same as those identified in the Minimum Investment Required Expansion Plan.

2.3 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.[11]

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. The survey was administered by a third-party research partner, and more than 2,000 responses were received. Findings show respondents:

- Are concerned about the rising cost of living, including electricity rates;
- Prioritize lower electricity rates over improvements in reliability or clean energy;
- Recognize that the province has a reliable system that is supplied largely from renewables;
- Agree that Hydro needs to prepare for growing electricity needs; and
- Have no broad alignment in their preference for types of new electricity sources.

Hydro's recommendations for BDE Unit 8 and the Avalon CT align with customer feedback on cost, reliability and clean energy—both have consistently been identified as the least-cost options and both meet Hydro's mandate of providing electricity in an environmentally responsible manner.

[11] "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

The Avalon CT is considered a peaking resource that does not need to operate continuously to support the system like traditional thermal resources, with models indicating that overall emissions associated with electricity generation could be reduced by over 80%.[12]

The engagement also confirmed that the Muskrat Falls project remains top of mind for customers—overall feedback highlights are provided in Figure 3.[13]

In progressing these capacity additions, Hydro is working to ensure appropriate scrutiny of its decisions while listening to customer feedback and 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 2025 Build Application for new generation is under the consideration of the Board in a transparent process.

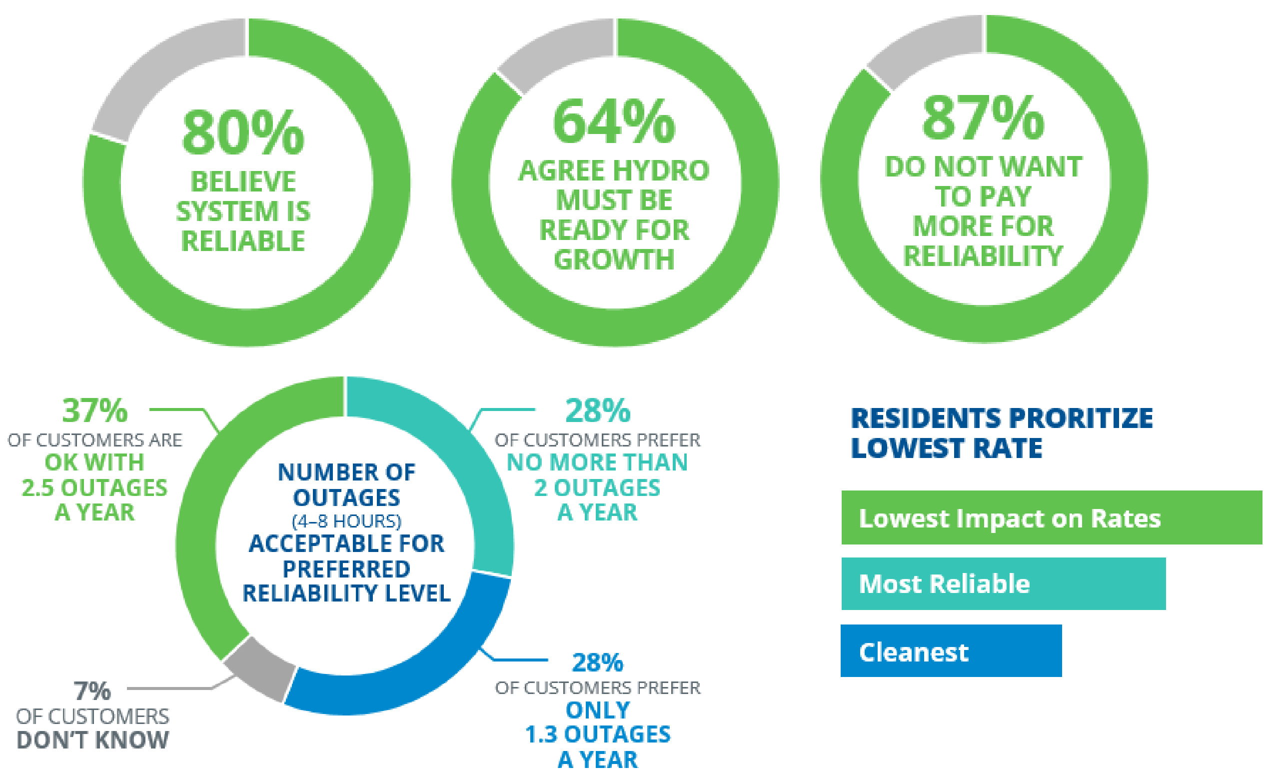


Figure 3: Public Engagement Feedback

[12] Based on CT usage following the retirement of the Holyrood TGS, modelled in the Slow Decarbonization forecast, which assumes a high level of LIL reliability (1% LIL bipole Equivalent Forced Outage Rate ("EqFOR")).
[13] Please refer to the 2024 Resource Adequacy Plan, app. D.

System expansion will increase rates, and public engagement confirmed that customers prioritize lower electricity rates and system reliability over clean energy resources. This customer feedback supports Hydro's Minimum Investment Required approach.

***Based on customer feedback, Hydro's proposed projects are based on a conservative "Minimum Investment Required" approach—outlining only what absolutely must be done to support reliability and prepare for load growth*.**

Electricity rates are a concern for customers; however, the Government of Newfoundland and Labrador ("Government") stated publicly that it is committed to rate mitigation of Hydro's costs post-2030 for Island ratepayers. Further discussion on customer rate implications of the projects proposed in this application is provided in Section 8.0.

2.4 Minimum Investment Required Expansion Plan

Through its analysis, Hydro recommended its Minimum Investment Required Expansion Plan. As outlined in this application, BDE Unit 8 and the Avalon CT are the foundational first steps to reliably serve customers on the Island Interconnected System as system demand grows in the coming decade. By focusing on foundational capacity supply options in the Minimum Investment Required case, Hydro addresses the immediate need for additional resources to meet the growing demand for electricity in Newfoundland and Labrador. The recommended Expansion Plan also provides the additional benefit of diversity in the system.

BDE Unit 8 and the Avalon CT are consistently shown to be the least-cost solutions across a broad range of sensitivities. In total, Hydro modelled 39 scenarios through the 2024 Resource Adequacy Plan, and BDE Unit 8 and the Avalon CT were chosen as the least-cost option by the model 85% and 74% of the time, respectively.[14] Further, BDE Unit 8 and the Avalon CT remain the least-cost options, even if capital cost estimates or fuel costs increased by 50%.[15]

A marine terminal at the site of the Avalon CT, along with the associated commercial supply agreements, while not a near-term requirement, was identified as a future option to further ensure the long-term fuel security for the proposed CT and any future CTs.[16] Other factors, such as plans to mitigate the long-term risk around fuel supply and transmission constraints, are important considerations when planning for the Reference Case. These factors are being further studied, but do not impact Hydro's proposed projects in the 2025 Build Application.

The addition of a 150 MW CT is confirmed to be feasible in consideration of the existing fuel supply chain on the Island of Newfoundland.

To demonstrate that BDE Unit 8 and the Avalon CT remain the least-cost, prudent options to serve its customers following the 2024 Resource Adequacy Plan, Hydro updated its Expansion Plan analysis ("Expansion Plan Update") to incorporate the latest available information, including an updated load forecast and updated cost estimates; this analysis is summarized in Section 3.0, and provided in detail in Schedule 3.

The analysis confirms the solutions identified in the 2024 Resource Adequacy Plan remain the technically viable and least-cost solutions to meet future electricity needs on the island.

Further, the Minimum Investment Required Expansion Plan included the integration of wind generation, which was also identified as a requirement to reliably serve the Island Interconnected System within the

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[14] "Technical Conference #4: Expansion Plan, Insights and Next Steps," 2024 Resource Adequacy Plan Technical Conference, October 29, 2024, slide 33. http://pub.nl.ca/applications/NLH2018ReliabilityAdequacy/correspondence/From%20NLH%20-%20Presentation%20-%20Technical%20Conference%204%20-%20Expansion%20Plan,%20Insights%20and%20Next%20Steps%20-%202024-10-29.PDF.
For further details on Hydro's Expansion Plan analysis, please refer to the 2024 Resource Adequacy Plan, app. C.
[15] "Technical Conference #4: Expansion Plan, Insights and Next Steps," 2024 Resource Adequacy Plan Technical Conference, October 29, 2024, slide 33.
[16] Without expanded confirmed fuel supply investments on the Island, Hydro would not have a reliable supply of fuel that additional CTs, beyond the 150 MW CT proposed in this application, would require to run reliably. This is a primary consideration for the 2026 Resource Adequacy Plan and future resource planning.

2024 Resource Adequacy Plan. The 2024 analysis identified a requirement for 400 MW of wind; Hydro is pursuing further studies in support of reliability and supply adequacy to maximize energy delivery to the Island over the LIL, potentially reducing this requirement.

The outcome will inform the expression of interest ("EOI") process, which will be conducted in parallel to the build application process in 2025 to help determine resource options and costs to meet the Island Interconnected System energy requirements; however, these potential solutions will not reduce the capacity requirements for the Island Interconnected System recommended in this application.

Wind does not form part of Hydro's 2025 Build Application. Rather, Hydro will continue its ongoing analysis and will proceed with an EOI to identify potential wind developers and development opportunities. As wind requirements are confirmed, Hydro will be in a position to issue a request for proposal ("RFP") for wind development and will inform the Board about progress toward such procurement.

3.0 Expansion Plan Update

To support the previously filed recommendation to proceed with the addition of new supply, Hydro has provided its Expansion Plan Update, reflecting the 2024 Load Forecast update which confirms that the requirement for additional resources remains. In addition, Hydro's Expansion Plan Update reflects refined capital estimates for supply alternatives, including Class 3 cost estimates for BDE Unit 8 and the Avalon CT, and escalated Class 5 cost estimates for other supply stack alternatives.[17] The analysis is provided in detail as Schedule 3 of this application.

Hydro's updated analysis has confirmed that the capacity options identified in the Minimum Investment Required Expansion Plan—both BDE Unit 8 and the Avalon CT—are required and remain the least-cost resource options to meet system reliability.

While Hydro has recommended its Minimum Investment Required Expansion Plan as a foundational first step toward meeting expected customer demand, Hydro recognizes the need for continued decision-

[17] Hydro's analysis in the 2024 Resource Adequacy Plan considered Hydro's 2023 Load Forecast and Class 5 cost estimates for resource options in Hydro's supply stack.

making to meet the Reference Case. Hydro's Minimum Investment Required Expansion Plan adds 385 MW and 1.4 TWh of energy to the system. An additional 140 MW and 0.4 TWh are required to meet the Reference Case Expansion Plan. Hydro's expansion plan to meet the incremental requirements for the Reference Case will be included in the 2026 Resource Adequacy Plan. Future build applications that may occur as a result of the next Resource Adequacy Plan study will be informed by the feedback gathered from the Board and Intervenors, including feedback received during the consideration of this application.

3.1 2024 Load Forecast Update

Hydro revises its load forecast annually, taking into account shifting economic factors, consumer behaviours, technological advancements and adoption rates, and policy considerations. Since filing its 2024 Resource Adequacy Plan, which was completed using the 2023 Load Forecast, Hydro has completed its 2024 Load Forecast update. Consistent with the 2023 load forecasts used in the 2024 Resource Adequacy Plan, Hydro's 2024 Load Forecast consists of three forecasts which were developed to reflect a range of Island Interconnected System load requirements, as summarized in Figure 4.

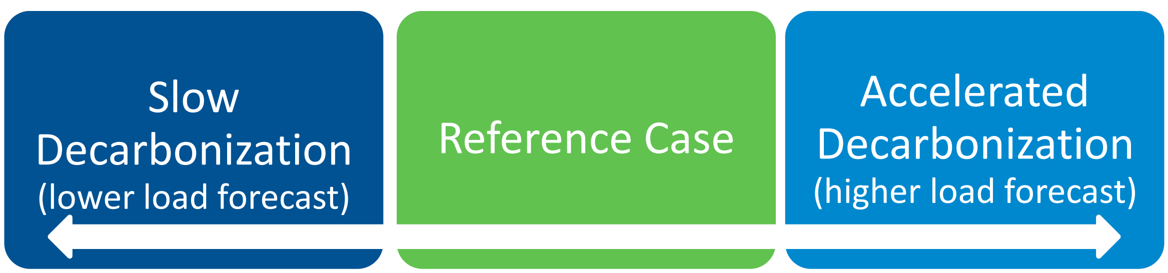

Figure 4: Island Interconnected System Forecast Scenarios

Hydro's 2024 Load Forecast presents a slightly more conservative outlook compared to the 2023 forecast; however, the difference is not material in the Reference Case or in the Slow Decarbonization scenario. While overall electricity demand and energy requirements continue to grow, updates to economic modeling, housing projections, and technological advancements have led to modest downward adjustments in the forecast.

Comparing the year-over-year Slow Decarbonization scenario, which drives Hydro's recommended Minimum Investment Required Expansion Plan, the demand in the 2024 forecast reduced by 0.4%, or 8 MW by 2034, which is a negligible difference from 2023 as shown in Chart 1. The slight decline is reflective of updated economic activity inputs, such as housing starts.

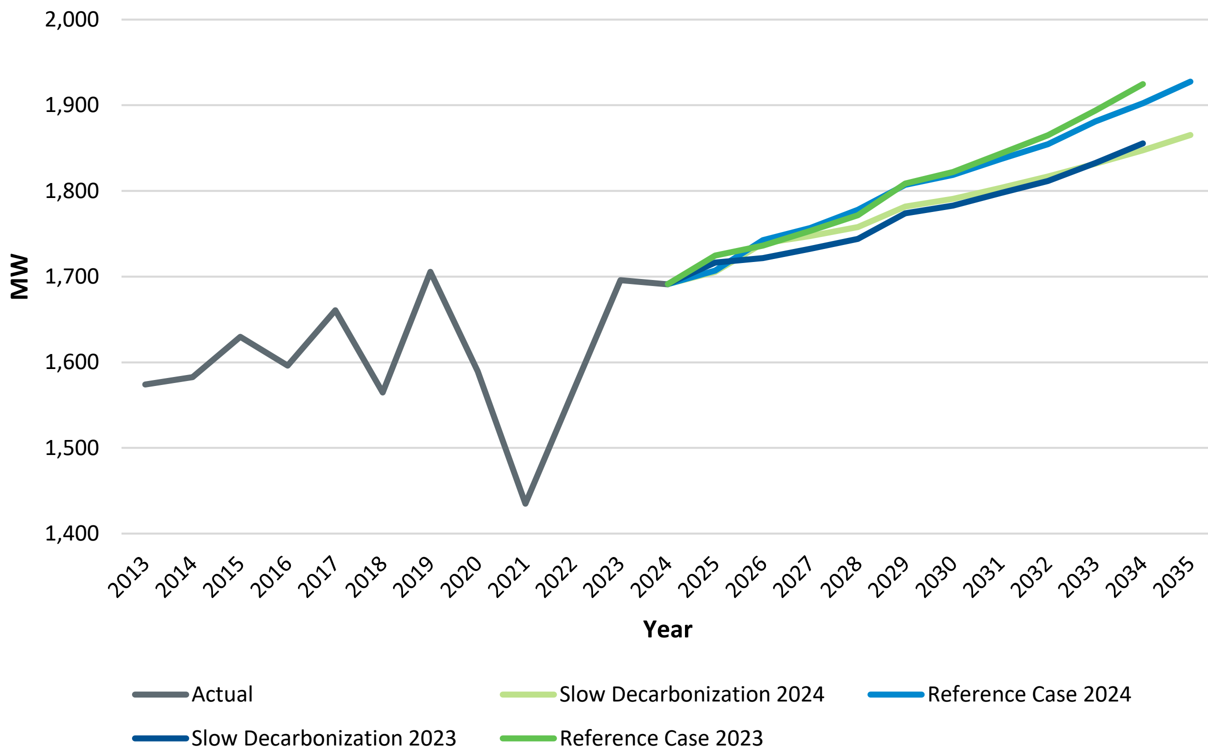

Chart 1: Island Interconnected System Annual Customer Coincident Demand Requirements Comparisons[18,19,20]

The 2024 Slow Decarbonization load forecast, which drives Hydro's recommended Minimum Investment Expansion Plan, is consistent with the 2023 Slow Decarbonization load forecast.

The impact of the updated load forecast on Hydro's recommended Expansion Plan is summarized in Section 3.2. The 2024 Load Forecast Report is provided as Appendix A to Schedule 3 of this application.

3.2 Results of Expansion Plan Update

Expansion Plan Scenarios

In Hydro's Expansion Plan Update, Hydro focused on updating two of the eight scenarios analyzed in the 2024 Resource Adequacy Plan: "Reference Case" or Scenario 1, and "Minimum Investment Required" or

[18] The Island Interconnected System annual customer coincident demand is reflective of the total Island Interconnected System demand less transmission losses and station service load.
[19] Historical values are not weather-normalized.
[20] The significant decline in demand in 2020 and 2021 was due to the effects of the COVID-19 pandemic.

Scenario 4. The analysis was completed on the basis of Hydro's previously established resource planning criteria, consistent with Hydro's 2024 Resource Adequacy Plan. Major inputs are summarized below:

- **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 2024 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.
- **Scenario 4 (Minimum Investment Required):** Represents the scenario requiring the minimum investment (i.e., 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 (2024 Slow Decarbonization forecast) that can be reasonably anticipated on the Island Interconnected System. This scenario was intended to bookend the Expansion Plan scenarios created in the 2024 Resource Adequacy Plan by identifying the Minimum Investment Required on the Island Interconnected System.

Hydro's Recommended Expansion Plan

Hydro's Minimum Investment Required Expansion Plan, as reported in the 2024 Resource Adequacy Plan, is based on a sensitivity[21] of Scenario 4, and Hydro's updated analysis of the Minimum Investment Required case is summarized herein. Fulsome analysis and discussion of the Expansion Plan Update for both the Reference Case (Scenario 1) and Minimum Investment Required (Scenario 4) is provided in Schedule 3 of this application.

Ultimately, Hydro's recommendations in the 2024 Resource Adequacy Plan included:

- The in-service date of BDE Unit 8 in 2031;
- The in-service date of Avalon CT in 2031 to meet the shortfall criteria;[22] and,
- The addition of 400 MW of wind as an energy resource by 2034.[23]

[21] Sensitivities are parameters that are varied to test select scenarios.
[22] To meet the LIL shortfall criteria described in Schedule 3 of this application, Hydro advanced the in-service date of the CT. Hydro's proposal in the 2025 Build Application estimates an in-service date of 2029 to both meet the shortfall criteria and support the retirement of aging thermal assets including the Holyrood TGS in advance of 2031.
[23] Added incrementally in blocks of 100 MW beginning in 2030. An 88 MW capacity contribution is included for wind as well.

Hydro is working to advance both capacity resources as fast as possible to reduce the reliance on aging thermal assets and reduce costs associated with maintaining and operating these assets. As a result, Hydro has advanced the in-service date of the CT within the 2025 Build Application to 2029.

In the 2024 Resource Adequacy Plan, Hydro initially established 11 sensitivities[24] to test Scenario 1 (Reference Case) and Scenario 4 (Minimum Investment Required). The recommended Minimum Investment Required Expansion Plan is based upon a sensitivity which considers a fixed wind profile to meet Hydro's firm energy criteria,[25] excludes batteries as a resource option, [26] and limits the number of CTs that can be constructed to one, approximately 150 MW CT in consideration of current diesel fuel supply availability on the Island.

Hydro's recommended Minimum Investment Required Expansion Plan was the starting point for the Expansion Plan Update analysis. For the purposes of the 2025 Build Application, seven additional sensitivities were created to test the Reference Case and Minimum Investment Required scenarios. Most sensitivities are slight modifications of, or combinations of, the sensitivities included in the 2024 Resource Adequacy Plan. These additional sensitivities can be found in Schedule 3, Table 3 of this application.

The Expansion Plan Update continues to support Hydro's recommended Minimum Investment Required Expansion Plan, which is summarized in Table 1. No expansion generation units are required in the model prior to 2030 in any of the scenarios based on the assumption of maintaining existing thermal assets through the Bridging Period.[27] Hydro's recommended Minimum Investment Required Expansion

[24] The sensitivities considered parameters such as capital costs, fuel costs, limitations on certain resource options, variations in battery effective load carrying capability ("ELCC"), etc. For further information, please refer to the 2024 Resource Adequacy Plan, app. C, sec. 6.2.

[25] Hydro's firm energy criteria is such that the Island Interconnected System should have sufficient generating capability to supply all its firm energy requirements with firm system capability.

[26] Based on analysis performed by Hydro as part of the *RRA Study Review*, battery energy storage systems ("BESS") are emerging as a viable supply solution worthy of further consideration. However, there remain appreciable feasibility questions surrounding BESS solutions related to capability in emergency scenarios such as an extended outage to the LIL bipole. Given concerns regarding BESS solutions in the event of a LIL shortfall scenario, such solutions were not included as capacity resources in the Minimum Investment Required Expansion Plan, (i.e., the recommended expansion plan). Hydro is committed to further study of battery ELCC to inform the 2026 Resource Adequacy Plan. Additional information can be found in Hydro's response to PUB-NLH-339 of the *RRA Study Review*.

[27] The Bridging Period is defined as the period from the present until 2030; the year in which aging thermal assets are assumed to be retired. These assets 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. 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.

Plan results in approximately an additional 385 MW and 1.4 TWh added to the Island Interconnected System within the next ten years, consistent with what was reported in the 2024 Resource Adequacy Plan. As highlighted by the green cells, Table 1 shows both BDE Unit 8 and the Avalon CT coming into service in 2031. The Minimum Investment Required Expansion Plan also includes up to 400 MW of wind energy (in increments of 100 MW), with the first 100 MW block to be online in 2030, and another 200 MW to be online in 2031 and the last 100 MW block to be online in 2033 to meet firm energy planning criteria.

Table 1: Hydro's Recommended Expansion Plan – Expansion Plan Update Results[28]

Resource	2030	2031	2032	2033	2034	2035
BDE Unit 8 (MW)		**154**	154	154	154	154
CT (MW)		**142**	142	142	142	142
Wind (MW)[29]	**100**	**300**	300	**400**	400	400
Total Firm Capacity (MW)[30]	22	362	362	384	384	384
Total Firm Energy (GWh)[31]	350	1050	1050	1400	1400	1400

Taking into account the slight reductions in both demand and energy reflected in the 2024 Load Forecast, the analysis presented in the Expansion Plan Update continues to justify the requirement for both BDE Unit 8 and the Avalon CT as the least-cost resource options to meet the reliability requirements of the Island Interconnected System and therefore supports the 2025 Build Application. Additional details and all analysis completed for the Expansion Plan Update can be found in Schedule 3 of this application.

[28] Hydro has included the MW for each capacity resource as modelled within its Expansion Plan Update.
[29] Wind does not form part of the 2025 Build Application.
[30] The firm capacity offered by BDE Unit 8 and the Avalon CT is 100% of its rated capacity, 154 MW and 142 MW, respectively. The firm capacity of wind is assumed to be equivalent to 22% of its rated capacity, based on historic data from existing wind generation.
[31] Firm energy provided by wind generation is 350 GWh per 100 MW build. Neither BDE Unit 8 nor Avalon CT provide firm energy to the system.

This updated analysis confirms that Hydro's proposed additions are prudent and necessary to address electricity requirements, and Hydro's Minimum Investment Required Expansion Plan is a foundational first step in meeting the Reference Case scenario.

The recommended Minimum Investment Required Expansion Plan also achieves the following:

- **Meets all Planning Criteria** – Satisfies all planning and firm energy criteria while ensuring reliability, assuming a highly reliable LIL (1% bipole EqFOR) and the 2024 Slow Decarbonization load forecast.
- **Balances Cost, Reliability, and Transmission Needs** – Manages rotating outages within historical experience, considers least-cost transmission upgrades, to alleviate transmission bottlenecks and includes an Avalon CT with synchronous condenser capability.
- **Supports Transition from Aging Assets** – Limits new CTs to 150 MW to reflect existing Island fuel supply availability, facilitates retirement of aging thermal assets, and enhances planned maintenance and outage flexibility with the addition of BDE Unit 8.
- **Future-Proof and Diverse Resource Mix** – Aligns with *Clean Electricity Regulations ("CER*") compliance, considers flexible renewable fuel conversion, integrates diverse thermal, hydro, and energy resources, and reflects public preference for least-cost solutions.
- **Resilient and Politically Neutral** – Provides a strong foundation for meeting Reference Case requirements (5% LIL bipole EqFOR) and Reference Case load forecast, while remaining agnostic to current Canadian political and geopolitical environment.

3.3 Compliance with Clean Electricity Regulations

Hydro aims to align itself with Environment and Climate Change Canada, *CER*, and the goal for a net-zero greenhouse gas emissions economy by 2050. In December 2024, the Government of Canada finalized the *CER,*[32] the draft versions of which were key considerations in Hydro's evaluation of potential new sources of generation during the 2024 Resource Adequacy Plan. Hydro's goal of minimizing its

[32] Environment and Climate Change Canada. (2024). *Powering Canada's Future: Securing jobs, investments, and savings by building more affordable and reliable clean electricity.* Government of Canada. https://www.canada.ca/en/environment-climate-change/news/2024/12/powering-canadas-future-securing-jobs-investments-and-savings-by-building-more-affordable-and-reliable-clean-electricity.html.

environmental footprint by using less fossil fuel generation must be balanced with the goal of maintaining a reliable system at a reasonable cost. The Avalon CT will be fully compliant with the *CER* and able to utilize renewable fuels in the future. Further, 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 *CER* acknowledges the role that these resources will play in the transition to a clean electricity grid.

The Avalon CT would be compliant with the CER, based on Hydro's expected operation of the asset as a peaking unit, providing backup generation in the event of high-demand periods and/or contingency events.

A number of flexibility mechanisms, such as transferable compliance credits, are also part of the *CER*, which would give Hydro additional flexibility to use thermal generating assets to maintain a reliable system while maintaining compliance with the *CER*. Further discussion is provided in Section 6.1 of Schedule 3 of this application.

4.0 2025 Build Application

4.1 Hydro's Proposed Projects

To satisfy capacity requirements as identified through the 2024 Resource Adequacy Plan, and confirmed by Hydro's Expansion Plan Update, Hydro is proposing to install BDE Unit 8 and the Avalon CT. Through Hydro's analyses, it has been demonstrated that at a minimum, both capacity resources are needed to meet the forecast capacity shortfall within the next decade.

The existing development at the Bay d'Espoir Hydroelectric Generating Facility has a 600 MW capacity delivered via seven existing units and consists of upstream storage reservoirs, a forebay, a spillway, and two powerhouses. BDE Unit 8 will supplement the existing Bay d'Espoir Hydroelectric Development, via the use of the existing reservoir and Powerhouse 2. BDE Unit 8 is expected to have a capacity of 150 MW, which will help meet the system's requirement for additional capacity. As BDE Unit 8 will use the existing reservoir, there is no expected additional energy from this addition. Hydro is requesting the

Authorized Budget of $1.08 billion[33] for the BDE Unit 8 project. This value is inclusive of the Planned Project Budget[34] and Management Reserve,[35] and consistent with Justice LeBlanc's recommendations on probability values of estimates in the final report on the Muskrat Falls Inquiry.[36] The inclusion of a Management Reserve in the overall project budget is a finding of the Muskrat Falls Inquiry and is consistent with current best practices. Commissioner LeBlanc noted that *"A reasonable reserve for strategic risk should have been included in the Project's cost estimate and made known to [the Government of Newfoundland and Labrador]."*[37]

The Avalon CT will supplement system capacity by adding a new multi-unit 150 MW generating facility that will provide peaking power support and standby generation and enable reduced generation from Holyrood TGS. The location identified for the CT plant is the Holyrood TGS site. Hydro is requesting an Authorized Budget of $891 million[38] for the Avalon CT project. This value is inclusive of the Planned Project Budget and Management Reserve, consistent with Justice LeBlanc's recommendations on probability values of estimates in the final report on the Muskrat Falls Inquiry.

Consistent with the findings of the Muskrat Falls Inquiry, the Authorized Budget includes both the Planned Project Budget and a Management Reserve, used to manage strategic risks.

[33] Inclusive of costs included within Hydro's "Early Execution Capital Work – Bay d'Espoir Unit 8 and Avalon Combustion Turbine," Newfoundland and Labrador Hydro, March 12, 2025 ("Early Execution Application").
[34] The Planned Project Budget is comprised of the project capital cost estimate (construction direct and indirect costs), interest during construction ("IDC"), contingency and escalation.
[35] Management Reserve is an industry-standard tool that is used to manage strategic risk and to address issues that may arise that are outside of the control of Hydro. It serves as additional funds in a project budget that is set aside for strategic risks and potential external, uncontrollable factors that may arise throughout the course of the project. It is not intended to be used to accommodate foreseeable changes in scope, schedule, and cost that are within Hydro's control. Considered "unknown unknowns" that are within the project scope (e.g., government policy changes).
[36] "Muskrat Falls: A Misguided Project, Commission of Inquiry Respecting the Muskrat Falls Project," The Honourable Richard D. LeBlanc, Commissioner, March 5, 2020, vol. I, Key Recommendation 5, pp. 61–62.
[37] "Muskrat Falls: A Misguided Project, Commission of Inquiry Respecting the Muskrat Falls Project," The Honourable Richard D. LeBlanc, Commissioner, March 5, 2020, vol. I, Key Finding 41, p. 53.
[38] Inclusive of costs included within Hydro's Early Execution Application.

The Authorized Budget, set at P85[39] confidence level, encompasses the Base Cost,[40] IDC,[41] Escalation,[42] Contingency[43] and Management Reserve. This probabilistic estimating approach ensures proper risk assessment during budgeting exercises. The use of a P85 estimate is also consistent with Justice LeBlanc's recommendations in the final report on the Muskrat Falls Inquiry and is further supported by the complexity assessment rankings of both projects. Further detail on the development of Hydro's cost estimates is provided in Section 5.4, and project budgets are included in Schedules 4 and 5 of this application.

The estimated completion timeline of these projects aligns with Hydro's resource planning outlook and enables the earliest possible retirement of aging assets, including Holyrood TGS. BDE Unit 8 is expected to be operational and then fully commissioned in 2031. Procurement of critical components, including the turbine and generator, has been requested in Hydro's Early Execution Application currently before the Board. Approval of the Early Execution Application will mitigate risks associated with supply chain delays and market pressures to allow for project continuity through year-end 2025, while the Board and parties consider the 2025 Build Application. The Avalon CT is expected to be operational and fully commissioned in late 2029. The procurement risks are similar for the Avalon CT project, with procurement of the critical combustion turbine also requested in the Early Execution Application. These timelines assume that the Early Execution Application is approved in April 2025, and approval is received for the 2025 Build Application in the fourth quarter of 2025.[44] Later approvals for either application will introduce delays in project schedule that risk pushing project completion into future years at additional cost to customers.

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[39] A probabilistic cost estimate in which there is an 85% probability that the actual cost will be less than or equal to the budget.
[40] Base Cost includes prices for direct costs (i.e., equipment, materials, etc.) and indirect costs (i.e., access roads, engineering, and temporary camps) and design allowance, to account for natural changes and refinement of scope of work as engineering progresses.
[41] IDC is to account for the cost of borrowing during project construction.
[42] Escalation is to account for increases in labour costs and material prices over the course of construction of a multi-year project.
[43] Contingency is the amount of money allocated in the schedule or cost baseline for known risks with active response strategies. This amount is added to an estimate to allow for items, conditions, and events for which the outcome is uncertain and that experience shows will likely result in additional cost. Considered "known unknowns" that are within the project scope (e.g., geotechnical conditions).
[44] Hydro requested Board approval of the Early Execution Application to protect the schedule and costs while allowing for the time necessary for the overall regulatory proceeding. The project schedule assumes time for a thorough review and evaluation of the project through a 2025 Build Application regulatory proceeding necessary to obtain Board approval by the end of the fourth quarter of 2025.

4.2 Improved Project Governance and Execution

Hydro's application, seeking approval of BDE Unit 8 and the Avalon CT, incorporates lessons learned from the Muskrat Falls Inquiry, and incorporates what other Canadian utilities are doing for major projects.[45]

A Major Projects Governance Framework ("Governance Framework"), provided as Attachment 1 to this schedule, has been developed by the Major Projects Department and approved by Hydro's Board of Directors on February 25, 2025.[46] The BDE Unit 8 and Avalon CT projects will be executed and transitioned to operations in accordance with the Governance Framework.

Hydro is confident in its ability to execute these projects within this governance framework, supported by qualified project teams and an approach that reflects lessons learned from past projects, recommendations from the Muskrat Falls Inquiry, industry standards and good utility practice.

In developing its Governance Framework, Hydro has established three new committees to provide increased governance in the following areas:

- Steering Committee (Project Oversight);
- Risk Management; and
- Change Management.

These committees will ensure robust project oversight and thoughtful decision-making, ensuring risks are appropriately identified, analyzed, and mitigated and that the appropriate management of change is completed. In line with Hydro's legislated mandate, the committees will drive decision-making that is ultimately in the best interest of Hydro's customers by balancing cost and reliability.

The committees will advise Hydro's Board of Directors of the status of the projects and ensure an appropriate level of engagement throughout the project lifecycle, including regular checkpoints within

[45] Projects and programs with an anticipated cost of $50 million or greater.
[46] The Governance Framework is developed in consideration of the Project Management Institute's Governance of *Portfolios, Programs, and Projects*: *A Practice Guide* and the Institute of Internal Auditor's *Three Lines Model*.

the phased approval process. Hydro's phased approval process provides for multiple decision points that require reassessment and justification of the business case, preventing premature sanction decisions and continuation of previously approved projects if they no longer make business sense.

Utilizing lessons learned from other projects, Hydro has also improved its cost estimating processes. Hydro has made significant steps to mature its cost estimating and project budget development skills including:

- Improved front-end planning ("FEP") for major projects;
- Training on industry practices for cost estimating and project budget development for all levels of the organization; and
- Engagement of senior estimating embedded contractors with major project experience.

For the 2025 Build Application projects, Hydro has improved cost estimates by performing constructability reviews; utilizing the Association for the Advancement of Cost Engineering ("AACE") Guidelines for estimate accuracy including maturity matrices, and performing quantitative risk analysis for project budget development.

In acting on recommendations from the Muskrat Falls Inquiry, Hydro has performed more FEP and engineering prior to requesting project approval and has matured its cost estimates to AACE Class 3 estimates; has identified P85 cost estimates informed by comprehensive risk analysis; and established a management reserve to help Hydro manage strategic risks. As part of the Governance Framework, the authorization for spending Management Reserve, which falls outside of the Planned Project Budget, requires approval from Hydro's Chief Executive Officer ("CEO").

Decision-making authority for BDE Unit 8 and the Avalon CT rests with Hydro employees on the Project Management Team. The Hydro Project Management Team is comprised of Hydro employees, and led by the Director, Major Projects and Asset Management and two Senior Managers who are collectively responsible for decision-making and project oversight.

Hydro is confident that it will successfully deliver these projects, utilizing lessons learned from previous experiences and a robust risk management strategy to mitigate risks to project cost and schedule. The success of the projects is dependent on the comprehensive approach Hydro has laid out in this application, to ensure that Hydro has the necessary authority and budget required to enable the project team to remain focused on the execution of the projects within the proposed schedule and avoid process delays which would impact project delivery. Hydro's readiness to undertake these projects is presented in Section 7.0.

The successful delivery of BDE Unit 8 and Avalon CT depends on Hydro's ability to proceed as outlined in this application, with the necessary authority and approved budget in place to immediately respond to risks. Hydro's approach is to ensure continuous progress and prevent delays that could arise from additional approval processes, allowing the project team to remain focused on execution and adherence to the proposed schedule.

Hydro has undertaken significant engineering and planning to ensure the scope, costs, schedules, and risks associated with these projects are understood and, to ensure stakeholders are equipped with the information necessary to make these critical decisions; these project details are summarized in Section 6.0, and provided in fulsome detail in Schedules 4 and 5 of this application.

4.3 Commentary on New Energy Partnership

The December 2024 Memorandum of Understanding for the New Energy Partnership between Hydro and Hydro-Québec ("New Energy Partnership") and associated new developments will enable an increase in capacity in Labrador. This does not impact Hydro's recommendation for the proposed generation within the Minimum Investment Required Expansion Plan for the Island Interconnected System. As accessing generation in Labrador to supply the island would require the addition of a second HVdc[47] link, including the addition of new converter stations, the increased generation in Labrador does not offer any island supply solutions that are cost-competitive with the proposed solutions identified in this application and cannot mitigate the risks associated with a LIL shortfall.[48] Therefore, the proposed projects associated with the New Energy Partnership do not provide an alternative for the additional on-Island generation identified in the 2024 Resource Adequacy Plan.

[47] High-Voltage Direct Current ("HVdc").
[48] Please refer to Hydro's response to CA-NLH-061 of the *RRA Study Review*.

4.4 Importance of Timely Decision Making

The planning, construction, and integration of new generating resources will take years, underscoring the need for expedient action. Project estimates are time-sensitive and supply chain pressures continue to increase; therefore any delay during the regulatory proceeding schedule or during project execution increases the risk of higher costs to ratepayers. Hydro's Early Execution Application was made with these risks and implications in mind.

Should project peak construction timelines align with the potential New Energy Partnership project period, the compounded effects of competition, resource shortages, and economic pressures could result in cost increases.

Based on the current timelines of BDE Unit 8 and the Avalon CT, the critical work is expected to be completed just ahead of the major construction associated with the New Energy Partnership projects. However, Hydro is also conscious of the implications the projects associated with the New Energy Partnership could have on the cost and schedule of Hydro's upcoming proposals if delays cause the project timelines to overlap. Hydro has conducted a review of the key risk factors impacting these projects. The analysis reveals potential cost pressures arising from both economic and resource-related challenges in that circumstance. An overlap would create competition for limited resources, including skilled contractors, hydro turbine suppliers, and construction labour. The heightened demand has the potential to increase costs, with procurement challenges and extended lead times for critical components further compounding schedule and budget pressures.

Economic factors also pose potential risks. If project timelines do not progress as proposed in this application and instead align with the New Energy Partnership projects, macroeconomic pressures such as rising commodity prices, inflationary trends, tariffs, and higher interest rates during construction could have a significant impact. Pricing adjustments to reflect increasing resource constraints are likely to occur, leading to higher financing costs. These combined factors could inflate project costs beyond the $30 million to $50 million annual estimate per project, particularly for BDE Unit 8 given the similarities in equipment, resources, and specialized skills required for hydroelectric construction projects proposed in the New Energy Partnership.

Timely decision-making remains the most effective method to ensure projects are delivered on budget and on schedule.

As the regulatory approval of projects is part of the critical path schedule, Hydro is committed to ensuring stakeholders are equipped with the information necessary to make decisions in a timely manner.

In line with customer expectations, Hydro's proposed projects, BDE Unit 8 and the Avalon CT continue to be the least-cost projects to provide reliable, electricity in an environmentally responsible manner. Delay in implementation of either of these capacity solutions will expose customers to risks of:

- Increased rate pressure as a result the increased costs associated with project delay;
- System reliability concerns potentially resulting in customer outages due to insufficient electricity supply, which could occur within the next ten years; and
- Continued investment, operation and reliance on aging thermal assets.[49]

5.0 Development of Proposed Projects

In preparing to execute the BDE Unit 8 and the Avalon CT projects, Hydro has done significant work in ensuring that it is listening to customers and taking action on key recommendations from the Muskrat Falls Inquiry, lessons learned from other major projects, and aligning itself with industry best practices. Hydro has taken seriously its responsibility to ensure that the Muskrat Falls Inquiry recommendations within its purview are reflected within the BDE Unit 8 and Avalon CT projects. Hydro has been maturing its cost estimating practices and project documentation, determining its project delivery strategy, identifying key project risks and beginning public engagement and consultation.

5.1 Readiness Reviews

Both the Avalon CT and BDE Unit 8 have concluded the FEP Phase, which lays the foundation for the successful execution of major projects by ensuring sufficient work is undertaken to clearly define the

[49] "Newfoundland and Labrador Hydro Holyrood Plant Capital Plan Refresh – HTGS 2025 Capital Refresh Report," Hatch Limited, March 4, 2025. http://pub.nl.ca/applications/NLH2018ReliabilityAdequacy/reports/From%20NLH%20-%20Holyrood%20Thermal%20Generating%20Station%20Capital%20Plan%20Refresh%20-%202025-03-07.PDF.

need, project strategy, scope, cost, and schedule to enable well-informed decision-making early in the project lifecycle.

The current project status includes the completion of an internal sanction readiness review undertaken by Hydro's Internal Audit and Advisory Services department. The purpose of the review was to determine if an appropriate governance structure has been established and is effective for this project and if Hydro had completed appropriate planning work for the build application from a cost, schedule and risk perspective. This review focused on three primary objectives, and aligned with the Board's capital budget requirements where applicable, including:

1) **Maturity of Deliverables for Class 3 Estimate as per AACE[50] guidelines and associated Schedule Risk:** Ensuring deliverables are at an appropriate stage as defined for an AACE Class 3 estimate. Deliverables are categorized into scope, capacity, requirements (e.g., regulatory requirements, safety, environment), strategy (e.g., contracting), planning (e.g., permitting, work breakdown structures, schedule, stakeholder plans), studies and technical deliverables (i.e., various designs). This objective also included assessing if both planning and schedule risks are identified and mitigated.

2) **Project Management Strategies:** Assessing the application of quantitative risk assessment methodologies, including Monte Carlo[51] simulations, to ensure comprehensive risk management and alignment to AACE Recommended Practice 40R-08 Contingency Estimating. This review also included ensuring that front-end engineering design ("FEED") align with AACE Recommended Practice 34r-05, Basis of Estimate, which is used to define time, resources and money required for a project.

3) **Stewardship with a focus on Governance**: Verifying the presence of governance structures to ensure effective oversight.

The review determined that the project documentation for both BDE Unit 8 and Avalon CT meet the requirements and expectations of the AACE guiding documents for the Class 3 Estimate. The cost and

[50] AACE. (2012). *Cost Estimate Classification System – As Applied in Engineering, Procurement, and Construction for the Hydropower Industries,* (AACE Recommended Practice RP 69R-12). AACE. (BDE Unit 8) or AACE. (1997). *Cost Estimate Classification System – As Applied in Engineering, Procurement, and Construction for the Process Industries*, (AACE Recommended Practice RP 18R-97). AACE. (Avalon CT).
[51] A probabilistic technique used to assess uncertainty and risk in cost projections.

schedule estimate is aligned with AACE requirements, including the Basis of Estimates and the quantitative risk assessment. An appropriate governance structure has been established and is operating effectively. Internal Audit and Advisory Services concluded that various recommendations and observations made throughout their review were incorporated into management's plans, as appropriate. No significant issues were identified during this process, and there are currently no outstanding issues or recommendations that would impact the 2025 Build Application.

5.2 Project Delivery

Hydro recommends proceeding with both projects under an Engineering, Procurement, and Construction Management ("EPCM") delivery model to balance Hydro's oversight with external expertise. This approach helps to ensure effective risk management, coordination, and the successful delivery of all phases, from design to commissioning.

Under this model, the EPCM consultant will be responsible for:

- **Design Functions:** Detailed design of the project;
- **Procurement Functions:** Contract administration, expediting, logistics/transport, and material control; and
- **Construction Management Functions:** Site project management, engineering, construction monitoring, and project controls.

There are five major benefits for Hydro in taking this approach:

1) Allows Hydro to form a strong Owner's Team[52] and leverage the expertise of the EPCM while retaining overall project control;

2) Empowers Hydro's team to adopt a management and oversight mandate, ensuring effective control of the EPCM consultant's performance;

3) Enables Hydro to focus efforts on Owner-led core activities such as financing, Environmental Assessment ("EA"), procurement, permitting, regulatory, and stakeholder engagement;

[52] An Owner provides strategic oversight and has overall responsibility for success of a project. Hydro is the Owner for the BDE Unit 8 and Avalon CT projects.

4) Utilizes proven systems and methods via the EPCM established systems, processes and procedures to drive efficiency and effectiveness; and

5) Provides the ability to allocate risks effectively through well-defined roles and responsibilities.

5.3 Risk Identification

Effective risk management is critical to the success of any project. It allows Hydro to proactively identify risks that could affect the project objectives which, in turn, increases the predictability of project outcomes; helps manage complexity; helps maintain project cost, schedule, and budget; supports change management; and generally supports the delivery of the intended strategic business objectives associated with the project. Hydro's overall approach to managing risk within major projects is detailed in Attachment 1 of this schedule.

On a project level, through FEP and FEED, Hydro worked to ensure it had a thorough understanding of the risks associated with each project and a fulsome Risk Register developed for each project. Project risks were then considered in the establishment of each project budget. The identification and quantification of risk was undertaken by subject matter experts, and a Quantitative Risk Analysis ("QRA") using a Monte Carlo simulation was employed to develop contingency and management reserve values which account for the risks identified. Key risks for the projects include timely decision-making (approval as well as during execution) and labour and equipment availability due to competing projects and other supply chain restrictions. For further detail on Project Risks and Risk Management please refer to Section 6.0 of Schedules 4 and 5 of this application.

5.4 Cost Estimating and Project Budgeting

Hydro has completed FEED on both the BDE Unit 8 and Avalon CT projects. A robust process was undertaken to ensure a reliable AACE Class 3 cost estimate has been produced for each project. As a result of estimate refinement, incorporating recommendations from the Muskrat Falls Inquiry and best practices within major projects, total project costs are higher than the Class 5 estimates which were considered within the $1.2 billion to $1.6 billion range included in the 2024 Resource Adequacy Plan. The increase is driven by a number of factors including supply chain pressures on pricing for major equipment, refinement of indirect cost estimates, increased financing costs and the addition of Management Reserves.

The Major Projects department has developed robust estimates and project budgets for these projects through comprehensive planning and using industry best practices and qualified personnel.

The Planned Project Budgets for major projects are the sum of the project capital cost estimate, IDC, and escalation. The Planned Project Budget does not include a Management Reserve. When the Management Reserve is added to the planned project budget, the Authorized Budget is determined. A detailed breakdown of each project estimate is provided in Appendix A of Schedule 4 and Appendix B of Schedule 5 of this application.

The project capital cost estimate includes the following:

- Base cost, which includes prices for direct costs, such as equipment, materials, labour, etc., and indirect costs, such as access roads, engineering, and temporary camps;
- Design allowance, to account for natural changes and refinement of scope of work as engineering progresses; and
- Contingency, to account for uncertainties outside of the Major Project’s Management Team’s control—they are the “known unknowns” that are within the project scope (e.g., geotechnical conditions).

The sum of these costs make up the project capital cost estimate.

To establish the Planned Project Budget, the following is also included:

- IDC, to account for the cost of borrowing during project construction; and
- Escalation, which accounts for anticipated increases in labour costs and material prices over the course of construction of a multi-year project.

Once approved, the Planned Project Budget is the amount that the Major Project Management Team has access to and is responsible for managing throughout the project. The entirety of the Planned Project Budget is expected to be used throughout the project.

As identified within the Muskrat Falls Inquiry, for large and complex projects, it is prudent to set aside additional funds for strategic risks and potential external, uncontrollable factors that may arise throughout the course of the project. This is known as the Management Reserve.

The Management Reserve is not readily accessible to the Major Project Management Team and its use must be approved by the CEO. Management Reserve is expected to be used on an as-required basis for issues which arise that are unforeseen and outside of the control of Hydro. It is not intended to be used to accommodate foreseeable changes in scope, schedule, and cost that are within Hydro's control. It can be used to cover items such as governmental policy changes, economic volatility, natural disasters not foreseen during the project development, unforeseen supplier delays, etc. The Management Reserve equips management so they can respond to strategic risks or unforeseen events quickly, and not further negatively impact the schedule and therefore cost of the project. Projects can keep moving forward and remain on schedule despite obstacles outside of Hydro's control. It is industry standard to include management reserve in project estimates especially for large complex projects, and was a key finding within the Muskrat Falls Inquiry. A well-managed Management Reserve is a crucial tool since it increases the likelihood that the project will succeed.

A QRA, used to facilitate estimating activities, is defined as a "Risk analysis used to estimate a numerical value (usually probabilistic) on risk outcomes wherein risk probabilities of occurrence and impact values are used directly."[53] QRA involves the collection of data with regard to cost, schedule and risk to model the project using an industry-standard statistical modelling tool. This analysis output is then used in a Monte Carlo simulation, a probabilistic technique used to assess uncertainty and risk in cost projections. Instead of relying on a single-point estimate, the Monte Carlo method runs thousands of simulations

[53] AACE. (2024). *Cost Engineering Terminology* (AACE Recommended Practice RP 10S-90, p. 104). AACE.

using different possible values for cost inputs, generating a range of possible outcomes with associated probabilities.

The outcomes of all of these calculations and analyses provide a statistical probability curve of outcomes for the overall project, informing the Management Team on recommended values for contingency and Management Reserve. Picking a point on this curve provides the probabilistic outcome at that point, also called the "P-Value" (e.g., P50 equates to a 50% probability that the project will be less than or equal to the project budget). This P-Value is the amount that the Hydro Board of Directors and the Regulator have been asked to approve. This total will be referred to as the **"**Authorized Budget" as shown in Figure 5.

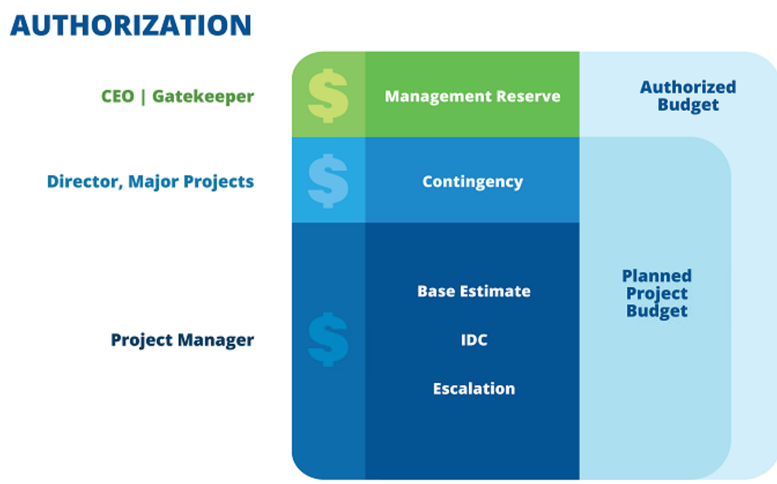

Figure 5: Authorized Budget and Planned Project Budget

The Authorized Budget that Hydro is reflecting within this application is a P85 cost estimate for both the BDE Unit 8 and Avalon CT projects. The use of a P85 estimate is consistent with Justice LeBlanc's recommendations in the final report on the Muskrat Falls Inquiry and is further supported by the complexity assessment rankings of both projects.

For further details on the methodology used to develop the estimates, please refer to Section 3.0 of Schedules 4 and 5 of this application.

5.5 Environmental and Public Engagement

As currently defined, the projects are subject to the provincial EA process and are required to be registered under the *Environmental Protection Act*. Hydro plans to submit EA registration for each project, and once released from the EA process, Hydro will acquire any further environmental permits, approvals and/or authorizations.

Environmental considerations have been prioritized, as the projects are situated on brownfield sites which minimizes ecological disruption while aligning with Hydro's commitment to environmental stewardship and sustainable development.

Extensive stakeholder engagement has been conducted to support a collaborative approach to each project execution. Hydro has implemented a proactive stakeholder engagement strategy for the projects, focusing on early communication, public input opportunities, and sustained collaboration throughout the project's planning, approvals, and execution phases.

The efforts of these engagements have resulted in a stronger understanding of stakeholder priorities and an ongoing commitment to transparency and collaboration, ensuring the projects align with community needs and expectations.

5.5.1 Stakeholder Engagement and Management Strategy

Hydro's approach to stakeholder engagement and management is built on proactive engagement, transparency, and collaboration. The following key strategies are being employed to ensure effective stakeholder communication and responsiveness:

- **Multi-Channel Communication:** Utilizing diverse communication methods such as direct invitations, social media outreach, traditional media (including radio and print), and public meetings ensures broad engagement and accessibility of information.
- **Early Consultation:** Engaging key interested groups early in the process fosters trust and allows stakeholders to provide input that may influence project decisions.
- **Stakeholder-Specific Outreach:** Tailored outreach efforts ensure that each stakeholder group receives information relevant to their interests, whether they be government officials, business leaders, environmental groups, or residents.

- **Dedicated Engagement Forums:** Open houses, guided tours, and targeted presentations create structured opportunities for stakeholders to ask questions, voice concerns, and receive direct responses from Hydro representatives.
- **Ongoing Monitoring & Feedback Integration:** Feedback from stakeholders is being documented and considered as part of ongoing project planning. Digital and physical feedback forms allow continuous input collection beyond engagement events.

Hydro is committed to ongoing engagement and keeping employees, the public, and other interested groups informed of progress as work moves forward. Further information regarding the stakeholder engagement sessions held with project-specific stakeholders (e.g., industry organizations, municipalities, etc.) is provided in Schedules 4 and 5 of this application.

6.0 Project Evidence Synopsis

6.1 Bay d'Espoir Unit 8

The following is a summary of the BDE Unit 8 project; fulsome evidence in support of this project is provided in Schedule 4 of this application.

6.1.1 Project Description

The Bay d'Espoir Hydroelectric Generating Facility is located on the south coast of Newfoundland and Labrador. It lies within the island portion of the province and utilizes the natural geography of the bay and surrounding areas to produce electricity, making Bay d'Espoir critical to the provincial power grid.

The existing facility consists of upstream storage reservoirs, a forebay, a spillway, and two powerhouses which together form an integral part of the hydroelectric system.

Powerhouse 1 is equipped with six generating units, each with a capacity of 75 MW, providing a combined output of 450 MW. The facility utilizes three water intakes, each connected to a penstock. These penstocks are designed to deliver water to two generating units each through a bifurcation system located near the powerhouse, ensuring distribution of water for energy generation. The first four generating units were commissioned during Phase 1 in 1967, while the remaining two units were commissioned in 1970 during Phase 2. A single headrace canal supplies water to the three intakes, optimizing flow and maintaining steady operations. The water is then discharged through a 4.5-kilometer-long tailrace channel, which directs the flow into Fortune Bay.

Powerhouse 2 houses a single 150 MW unit (Unit 7) and receives water through a dedicated headrace canal, intake, and penstock. Its tailrace channel connects to the tailrace channel of Powerhouse 1. Commissioned in 1977 during Phase 3, the powerhouse was built with provisions for adding a second 150 MW unit (Unit 8) in the future. To minimize disruptions to Unit 7 during the eventual construction of Unit 8, rock excavation for Unit 8 was completed and the downstream portion of the draft tube, including the draft tube gate guides, was constructed. However, the headrace canal, intake, penstock, and downstream section of the tailrace channel were designed and built exclusively for Unit 7. At the time, it was anticipated that the headrace canal and tailrace channels would be expanded and new intake and penstock systems would be added during the eventual installation of Unit 8.

In order to address the need for additional generation to meet system reliability requirements, Hydro proposes BDE Unit 8, a new 150 MW unit to be located in Powerhouse 2. As shown in Figure 6, Powerhouse 2 will be extended to accommodate Unit 8 adjacent to Unit 7. The development involves the construction of an enlarged headrace canal, featuring a bifurcation carved into the rock. This bifurcation will supply water to both the existing entrance channel leading to the current Unit 7 intake and a new entrance channel designed for the intake of a newly added Unit 8. Like Unit 7, Unit 8 will not require a surge tank. Additionally, a new water intake, designed to align with the specifications of the existing intakes, will be installed. A buried steel penstock will connect this new intake to the newly introduced generating unit. The project also includes the installation of the new generating unit itself and the addition of a service bay as part of an extension to the powerhouse. The addition of Unit 8 will require a high voltage 230 kV line from the Unit 8 generator step-up ("GSU") transformer to Terminal Station 2. The new facility will benefit from the existing powerhouse forebay and will not require the construction of new dams or modifications to existing dams, as it will utilize the existing Long Pond Reservoir without modification.

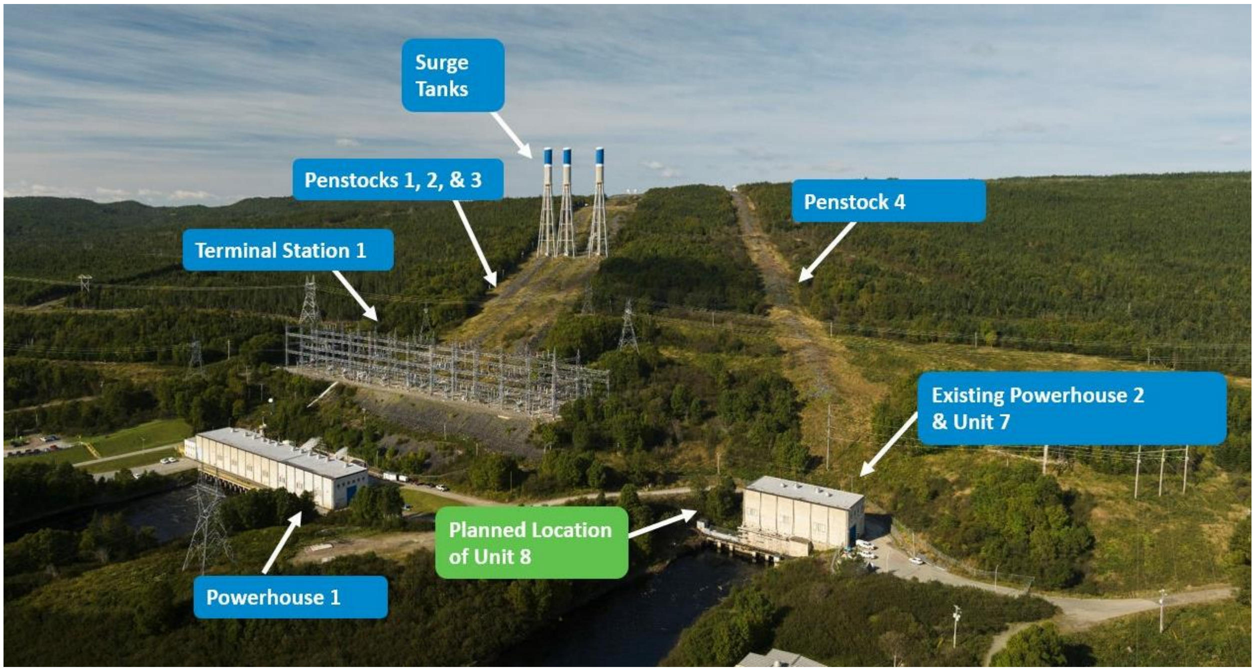

Figure 6: Proposed Intake and Penstock Area for Unit 8

6.1.2 Project Scope

This project will supplement the existing Bay d'Espoir Hydroelectric Generating Facility via the use of the existing reservoir and Powerhouse 2. Specifically, the project will include the engineering, procurement, construction, installation, commissioning, and testing of all works associated with the project, including:

- Excavation of new headrace canal;
- New intake, intake building, and ancillary services;
- New penstock;
- New turbine generator (150 MW) to be installed in the existing Powerhouse 2;
- New GSU transformer and isolated phase bus;
- New auxiliary mechanical, electrical, protection and control, telecontrol, and telecommunications and communications equipment;
- Modifications to Powerhouse 2, as required, to support Unit 8 installation, operation, and maintenance;
- Tailrace channel enhancements;

- A new 230 kV transmission line, which will include Optical Ground Wire, from the new Unit 8 GSU transformer to the existing Terminal Station 2; and
- Expansion and modifications to Terminal Station 2 to accept transmission line interconnection.

6.1.3 Early Execution

As identified in the Early Execution Application, certain advance work and analysis are required to protect the necessary timelines for construction and protect project budget, mitigate the impact to customers as a result of higher project costs associated with delays; and, ensure project continuity through year-end 2025.

Hydro did not seek cost recovery for the expenditures proposed in the Early Execution Application. This was to allow for as expedient of a review process as possible, in the interest of regulatory efficiency and minimization of increases in cost to ratepayers that would result from a delayed project in-service date.

For BDE Unit 8, these critical activities to accomplish in Early Execution works include:

- Engage EPCM contractor to support the following activities:
    - Complete geotechnical investigations and surveys that are needed to support the execution phase, as well as engineering and specifications for long lead or early equipment, such as Turbine and Generator Package, GSU transformer, draft tube stop logs, and 230kV breakers; and
    - Detailed execution planning activities, such as establishing final execution plan, contracting plan, and other planning documentation.
- Engage Turbine Generator original equipment manufacturers to complete Computational Fluid Dynamics modeling and model testing. The work would also include confirmation of the final supply and install pricing and schedule.
- Complete EA registration and continue with stakeholder engagement process.

These activities are part of the overall project; however, they were included within the Early Execution Application for early approval to prevent delays in the project schedule that would impact costs.

6.1.4 Project Cost

The Authorized Budget, set at a P85 confidence level in keeping with the Muskrat Falls Inquiry recommendation, encompasses the direct construction costs, indirect construction costs, contingency, escalation, IDC and Management Reserve. It is also inclusive of the costs outlined in the Early Execution Application which would occur regardless if completed as part of the larger application, albeit later, and with increased total project cost. Hydro is requesting an authorization of $1.08 billion for the BDE Unit 8 project.

6.1.5 Project Milestone Schedule

Table 2 provides the anticipated timelines for major milestones necessary to meet the schedule best positioned to achieve the cost and in-service timeline. Deviations from this schedule will increase costs and extend in-service accordingly.

Table 2: BDE Unit 8 Major Milestones

Milestone Description	Date
EA Registration	Q2 2025
Award EPCM Contract	Q3 2025
Build Application Approval	Q4 2025
Award Transformer Contract	2026
Final Award Turbine Contract	2027
Start On-Site Construction Works	2028
Powerhouse Enclosed	2030
Pit Free	2030
Start of Turbine Commissioning	2031
Turbine Ready for Commercial Operation	2031

Schedule Considerations and Risks

During the FEP phase, consultants were retained to design a contracting strategy, develop a contract packaging plan, and identify vendor packages for procurement. Key items, such as the turbine/generator and GSU transformer packages, were recognized as critical path elements for the project, with expected delivery timelines of five years and four years, respectively. Hydro has applied lessons learned from the procurement of large power transformers[54] within the current project to reflect updated delivery lead times and costs.

There are a number of risks that could impact the execution schedule, in particular timely approval, and competing projects. Hydro requested Board approval of the Early Execution Application to protect the schedule and costs while allowing for the time necessary for the overall regulatory proceeding. As identified in the Early Execution Application, certain advance work and analysis are required to protect the necessary timelines for construction and protect project budget, mitigate the impact to customers as a result of higher project costs associated with delays, and ensure project continuity through year-end 2025. The project schedule assumes time for a thorough review and evaluation of the project through a regulatory proceeding necessary to obtain Board approval by the end of the fourth quarter of 2025. Delays in receiving overall regulatory approval beyond the end of 2025 would have implications for the schedule, particularly the ability to award the long-lead contract for the turbine and generator unit.

Additionally, if Hydro does not have approval in time to allow the planned seasonal construction activities to commence as scheduled, there is an increased risk of a full-year delay. It is projected that there will be multiple, concurrent projects with similar timelines, both internal and external to Hydro. This creates a further strain for both equipment and skilled labour. This strain could lead to delays from suppliers and may influence the ability to attract and retain a skilled workforce to the area and project, which may negatively influence productivity and further jeopardize the schedule.

6.1.6 Updated Hydrology Study

In support of its 2025 Build Application, Hydro engaged Hatch Ltd. ("Hatch") to update its *Final Report for Hydrology and Feasibility Study for Potential Bay d'Espoir Hydroelectric Generating Unit No. 8* ("2020 Study").[55] Hydro asked Hatch to update the 2020 Study with most recent hydrology and assumptions,[56] including the 2024 Load Forecast, and to confirm its validity.

[54] "Purchase Spare Generator Step-Up Transformer," Newfoundland and Labrador Hydro, September 21, 2023.
[55] Please refer to the "Reliability and Resource Adequacy Study – 2022 Update" Newfoundland and Labrador Hydro, October 3, 2022, vol. III, att. 7.
[56] This study examined the effects of updated hydrology, the 2024 Reference Case load forecast, and recent history on frazil ice effects on generation. The addition of BDE Unit 8 in the Bay d'Espoir System was assessed in isolation, meaning external energy sources, such as the LIL, were not included as part of the analysis.

The scope of work of the updated study included background data review, hydrological analysis, and power and energy model analysis. The 2025 study, provided as Attachment 2 to this Schedule, confirms that the results of the previous study remain valid; however, the hydrology and 2024 load forecast update caused a minimal decrease in firm and average energy estimates. The study also re-examined the end-of-November recommended elevation ranges and reconfirmed the range from the 2020 Study, that is, the large storage reservoirs in the system to optimize Bay d'Espoir System generation in the winter months while allowing room for possible early winter high flow.

6.2 Avalon Combustion Turbine

The following is a summary of the Avalon CT project; fulsome evidence in support of this project is provided in Schedule 5 of this application.

6.2.1 Project Description

The Avalon CT, to be constructed on the site of the Holyrood TGS as shown in Figure 7, will supplement system capacity by adding a new multi-unit 150 MW generating facility, with supporting infrastructure and transmission interconnection that will provide peaking power support and standby generation in line with the 2024 Resource Adequacy Plan. It will assist with system reliability and reduce the reliance on the current Holyrood TGS. From an emissions and diesel fuel perspective, the Best Available Control Technology will be specified, and the integration of renewable fuels into the plant's operation will continue to be explored as technology and supply evolve.

Hydro believes that CT resources are a viable, least-cost option for supply within this province that meets Hydro's mandate and are consistent with customer feedback.

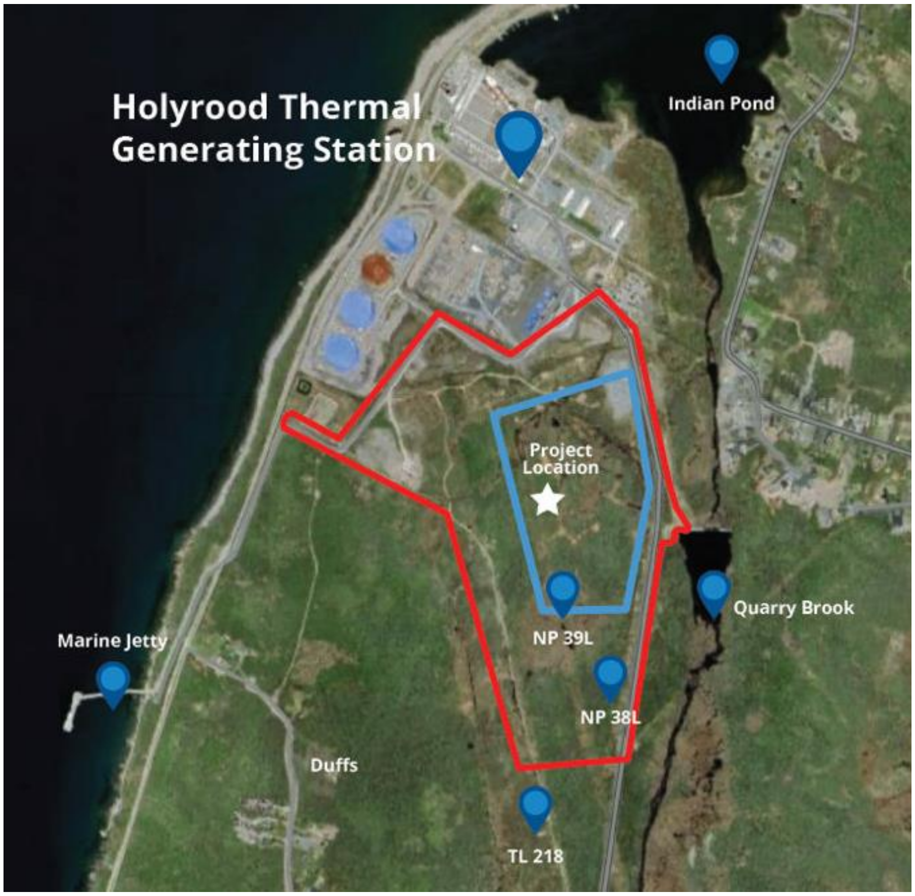

Figure 7: Site of Holyrood TGS and Future Avalon CT

The project encompasses the construction of a new plant to house the expected multiple CT generating units, associated transformers, and essential mechanical and electrical systems, including control and protection equipment, fire protection, a demineralized water plant, a compressed air system, and a black start generator. To support operations, a new raw water intake and pumphouse will be developed to supply water for both domestic use and the demineralized water plant. Additionally, the fuel offloading system will include a new fuel tank farm, a truck offload delivery system for plant supply, and provisions to enable a potential future interconnection to the existing Holyrood Marine Terminal.[57] Upgrades to the transmission and terminal station facilities involve establishing a new 230 kV high-voltage terminal station connected to the GSU transformers, along with modifications and rerouting of

[57] Hydro has included a provision for a pipeline; however, the final decision on execution of this scope is pending the outcome of the condition assessment on the current Holyrood TGS Marine Terminal and a decision to proceed with modifications to the Marine Terminal to allow delivery of diesel fuel.

existing transmission line TL218 and Newfoundland Power transmission lines into the new terminal station, ensuring seamless integration with the power system.

6.2.2 Project Scope

This project will include the engineering, procurement, construction, installation, commissioning, and testing of all works associated with the project, including:

- New No. 2 diesel tank farm and fuel delivery and transfer system;
- New raw water intake at Quarry Brook;
- New Combustion turbine-generator(s) (totalling approximately 150 MW);
- New Avalon CT plant complete with annexed control, water and black start buildings;
- New GSU transformers and isolated phase bus;
- New balance of plant auxiliary mechanical, electrical, protection and control, telecontrol, and telecommunications and communications equipment; and
- New Terminal Station and transmission Tie-in to existing transmission line TL218.

6.2.3 Early Execution

As identified in the Early Execution Application, certain advance work and analysis are required to protect the necessary timelines for construction and protect project budget, mitigate the impact to customers as a result of higher project costs associated with delays, and ensure project continuity through year-end 2025.

For the Avalon CT, these critical activities in Early Execution include:

- Critical Path RFP preparation for CT and GSU transformers. This entails the detailed engineering and fabrication scheduling necessary to complete the work and includes firm confirmation of the final supply and install pricing and schedule.
- Complete EA Report and Registration and continue with the stakeholder engagement process.
- Engage Engineering Support and prepare RFP for EPCM Contractor to support the following activities:
  - Complete geotechnical investigations and surveys needed to support the execution phase; and
  - Detailed execution planning activities, such as establishing final execution plan, contracting plan, and other planning documentation.
- Avalon CT interface optimization assessments in areas such as fire water supply, overall site fuel utilization, etc.
- Preparation of RFP and engage with contractors to complete initial geotechnical work and minor excavations in preparation to support transmission line relocation and new transmission line installations to ensure the overall schedule can be maintained.

These activities are part of the overall project; however, they were included within the Early Execution Application for early approval to prevent delays in the project schedule that would impact costs.

6.2.4 Project Cost

The Authorized Budget, set at a P85 confidence level in keeping with the Muskrat Falls Inquiry recommendation, encompasses the direct construction costs, indirect construction costs, contingency, escalation, IDC, and Management Reserve. It is also inclusive of the costs outlined in the Early Execution Application which would occur regardless if completed as part of the larger application, albeit later, and with increased total project cost. Hydro is requesting authorization of $891 million for the Avalon CT project.

6.2.5 Project Milestone Schedule

Table 3 provides the anticipated timelines for major milestones necessary to meet the schedule best positioned to achieve the cost and in-service timeline. Deviations from this schedule will increase costs and extend in-service accordingly.

Table 3: Avalon CT Major Milestones

Milestone Description	Date
EA Release	Q2 2025
Award Transformer Contract	Q2 2025
Award CT Contract	Q3 2025
Award EPCM Contract	Q3 2025
Build Application Approval	Q4 2025
Start Main On-Site Construction Works	2026
Start of Commissioning	2029
Turbine Ready for Commercial Operation	2029

Schedule Considerations and Risks

As aforementioned, Hydro is working to advance the Avalon CT as fast as possible to reduce the reliance on aging thermal assets and reduce costs associated with maintaining and operating these assets. As a result, Hydro has advanced the in-service date of the CT within the 2025 Build Application to late 2029. As outlined in the 2024 Resource Adequacy Plan, advancing the in-service date for the Avalon CT also continues to have a material benefit to the reliability of the Island Interconnected System in the event of a prolonged LIL bipole outage.

There are a number of risks that could impact the execution schedule, in particular timely approval, and competing projects. Hydro requested Board approval of the Early Execution Application to protect the schedule and costs while allowing for the time necessary for the overall regulatory proceeding. As identified in the Early Execution Application, certain advance work and analysis are required to protect the necessary timelines for construction and protect project budget, mitigate the impact to customers as a result of higher project costs associated with delays, and ensure project continuity through year-end 2025. The project schedule assumes time for a thorough review and evaluation of the project through a regulatory proceeding necessary to obtain Board approval by the end of the fourth quarter of 2025. Delays in receiving overall regulatory approval beyond the end of 2025 would have implications for the schedule, particularly the ability to award the long lead contract for the combustion turbine, which may negatively affect the overall schedule and lead to increased project costs. As well, it is projected that there will be multiple, concurrent projects with similar timelines, both internal and external to Hydro. This creates a strain on both equipment and skilled labour. This could lead to delays from suppliers and may influence the ability to attract and retain a skilled workforce to the area and project, which may negatively influence productivity and further jeopardize the schedule.

7.0 Major Projects Organizational Readiness

In recognition of the criticality of project oversight in the success of major projects, Hydro has increased the level of project oversight by utilizing both internal and external resources, and assembling a qualified team with the necessary breadth and depth of expertise. Hydro has also leveraged lessons learned from past projects to ensure success during planning and execution.

Hydro placed the execution of BDE Unit 8 and the Avalon CT work scopes under one department, Major Projects Department, which is dedicated to and responsible for the planning, execution, and delivery of Major Projects. This department brings together internal expertise related to Hydro's electrical system, project management, contract management, and project controls. The Major Projects Department also includes a number of contracted resources that have expertise in specific areas with larger-scale developments. The establishment of the Major Projects Department is prudent and necessary to provide the level of oversight required for success in large projects.

7.1 Lessons Learned

Hydro's ability to execute these projects is supported by highly qualified project teams and a governance framework that reflects lessons learned from past projects, industry standards and good utility practice. In addition to provincial history and lessons learned, Hydro researched current practice across Canada in light of current industry issues such as post COVID-19 supply chain difficulties and the acceleration of builds arising from increasing pace of electrification.

Hydro is ensuring the readiness of the organization to execute regulated major projects by leveraging insights gained from Hydro's Internal Audit and Advisory Services group, the Muskrat Falls Inquiry, other utilities such as members of the Canadian Electric Utility Project Management Network,[58] and lessons

[58] A Canadian utility industry working group consisting of major hydroelectric and transmission provincial corporations, with a focus on project management, engineering and commercial lessons learned across Major Projects.

learned from previous projects. These recommendations are embedded in the processes and standards in this application, including a Phased Approval Process and maturing cost estimating practices. A full summary of lessons learned is provided as Appendix A to this schedule.

Hydro is confident in its ability to deliver these projects, utilizing a robust risk management strategy to mitigate risks to project and schedule.

7.2 Major Projects Governance Framework

The Governance Framework provided in Attachment 1 to this schedule, provides an overview of Hydro's approach to governance of Major Projects, including how governance will integrate into and align with the broader Hydro organization, meet stakeholder expectations of Hydro as a crown utility, apply lessons learned, and align with Hydro's existing governance structure. It also provides an overview of the Major Projects Department, its purpose, and its guiding principles. The governance framework provides for transparency in decision-making and multiple governing bodies with access to all information necessary to support risk-informed and evidence-based decision-making.

The Governance Framework also addresses Hydro's approach to risk management for Major Projects, including the mechanisms in place to ensure integration into Hydro's existing Enterprise Risk Management processes. Additionally, the change management process and requirements applicable to Major Projects are outlined, including the role of change management in forecasting the impact of potential changes on project budget, scope, and schedule. The manner in which governance requirements are communicated and ensuring appropriate resources are in place to provide the necessary oversight is also described within the Governance Framework.

7.2.1 Governance Mechanisms

The Governance Framework describes the bodies that will manage and oversee Major Projects, including the Regulator who, under the *Public Utilities Act,* has responsibility for the general supervision of public utilities in the province and requires the Regulator to approve rates, capital expenditures and other aspects of the business of public utilities. The independent adjudication of applications for capital expenditures further enables external transparency through the regulatory process and regular reporting on project progress. The hierarchy of the governing bodies is shown in Figure 8, and more information on the competencies of Hydro's Board of Directors, the Reliability and Resource Adequacy and Major Projects Committee and Executive Leadership Team is found in Appendix B to this schedule.

In developing its Governance Framework, Hydro established three new committees:

1) The *Major Projects Steering Committee* ("Steering Committee") is comprised of Hydro's entire Executive Leadership Team, including the President and CEO. The other two committees described below will report to it monthly. The Steering Committee provides a forum for obtaining executive-level approvals; providing updates related to current progress; identifying challenges; raising issues; and seeking input, guidance and advice on matters of high significance.

2) The *Major Projects Risk Working Group ("Risk Working Group"),* primarily composed of members of the Major Projects Department's Management Team, provides a forum for comprehensive evaluation of risks. It also provides a mechanism to enable two-way communication from the Major Projects Department to the rest of Hydro about project and program activity that may affect Hydro's corporate activities and operations, and from the broader Hydro organization regarding corporate activities and operations that may affect projects, programs, and the Major Projects Department.

3) The *Major Projects Change Control Committee ("Change Control Committee")* is primarily comprised of members of the Major Projects Department's Management Team with additional representation from Hydro's Corporate Legal and Finance teams. The Change Control Committee provides a forum for comprehensive evaluation of proposed project and program changes and ensures effective management and approval of such changes.

The Steering Committee provides reporting to the Reliability and Resource Adequacy and Major Projects Committee, which is a committee of the Board of Directors that is responsible for reporting to Hydro's Board of Directors. The change management process, as outlined in the Governance Framework, will ensure accurate and timely reporting and communication of project budget, scope and schedule changes.

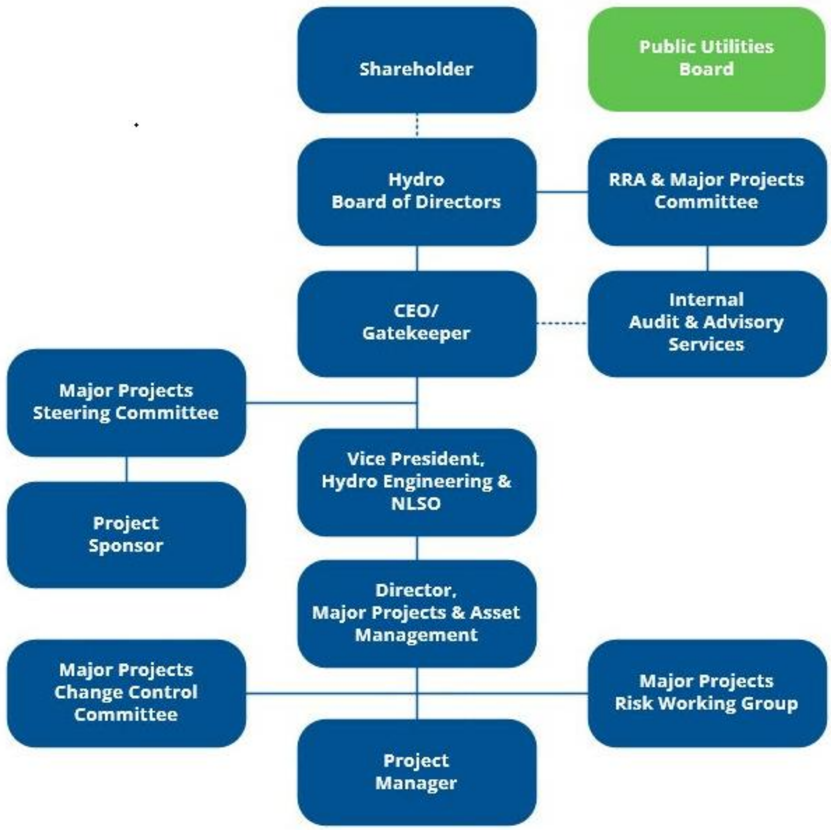

Figure 8: Major Projects Governance Structure[59]

7.2.2 Phased Approval Process

The Governance Framework also outlines the phased approval process, which serves as the high-level roadmap for Major Projects from the time a need is identified, through planning and execution, and into project handover and integration into Hydro's operation. It also indicates the various decision points at which the project will be assessed and critically evaluated.[60] The Major Projects Phased Approval Process is shown in Figure 9.

[59] The Terms of Reference for the Change Control Committee, Risk Working Group, and Steering Committee outline the purpose, composition, responsibilities, and expectations of each group and are attached to the Governance Framework.
[60] Hydro's intended Phased Approval Process was placed on the record as part of the Fall 2024 Technical Conferences for review and discussion. Please refer to "Technical Conference #4: Expansion Plan, Insights and Next Steps," 2024 Resource Adequacy Plan Technical Conference, October 29, 2024, slide 52.

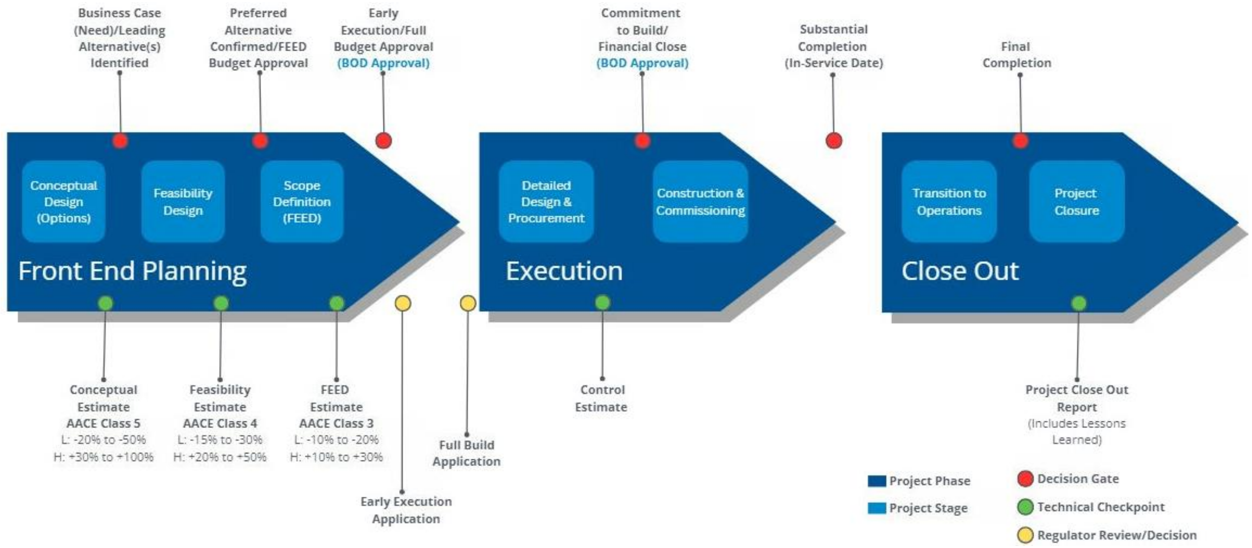

Figure 9: Hydro's Phased Approval Process for Major Projects

Approvals to Date

On February 25, 2025, Hydro's Board of Directors approved the BDE Unit 8 and Avalon CT projects and authorized Hydro to apply to the Board for regulatory approval. To inform its decision, the Board of Directors was provided with a Decision Support Package in accordance with the Governance Framework.[61]

At the same meeting, Hydro's Board of Directors approved Hydro's Early Execution requirements and authorized Hydro to apply for regulatory approval. Hydro's Early Execution Application was submitted on March 12, 2025, and the regulatory proceeding is ongoing.

7.2.3 Project Governance Activities

Engagement of Internal Audit and Advisory Services

Hydro engaged Internal Audit and Advisory Services more than one year ago to develop a long-term auditing strategy ("Audit Strategy") for both BDE Unit 8 and the Avalon CT. The Audit Strategy relies on several best practices including:

- Project Management Institute guide;
- AACE; and

[61] "Major Projects Governance Framework," Newfoundland and Labrador Hydro, March 5, 2025, sec. 10.2.4, pp. 30–31.

- The Construction Industry Institute.

The key focus areas will be project governance and project management. The areas of focus will change depending on the project's lifecycle. Lessons learned from auditing and project management of the Lower Churchill Project are also incorporated into the audit strategy.

Based on the audit strategy, continuous auditing will occur over the life of the project and all activities will be mapped against the Project Management Body of Knowledge by the Project Management Institute and Construction Industry Institute. As of February 2025, Internal Audit has completed several audits within the "Initiating" and "Planning" stages of the BDE Unit 8 project and the Avalon CT, along with the Governance of Major Projects. The department has also completed an extensive review of Hydro's readiness prior to submission of the 2025 Build Application.

Complexity Assessments

Major Projects with higher complexity require higher governance authority structure, resources, and processes. When there is a lower level of rigor in governance processes than required, risk is introduced. However, when there is a higher level of rigor in governance processes than required, inefficiency results.[62] An excess of either risk or inefficiency can result in delays, increased costs, and other undesirable outcomes that are not in the best interest of Hydro's customers.

To determine the complexity of the BDE Unit 8 and Avalon CT projects, Hydro's Internal Audit and Advisory Services Department facilitated complexity assessments of both projects. The complexity assessment is modelled based on the Project Management Institute's Navigating Complexity Guide. The complexity assessment collects information about various elements of each project (e.g., number of stakeholders, anticipated cost and duration, risk, etc.) and scores the projects accordingly. The complexity assessment ranked both projects as "Very High Complexity." Both projects therefore require a high degree of governance resources and effort.

7.3 Execution Capability

Hydro has experience in successfully executing projects of similar scale and scope in the last decade, including the construction of the Holyrood CT, executed between 2014 and 2015, and Transmission

[62] Project Management Institute. (2016). *Governance of Portfolios, Programs, and Projects: A Practice Guide* (p. 8). Project Management Institute.

Lines TL267 and TL266, executed between 2014 and 2018. Building on this history and experience, along with lessons learned, Hydro has assembled a qualified Major Projects Department that has the necessary expertise from within the utility industry, as well as other industries, to execute these large-scale projects. With a strong focus on quality, safety, and efficiency, the team applies proven strategies and industry best practices to ensure the delivery of complex initiatives on time and within budget.

7.3.1 Project Management Team

The management structure of Hydro's Major Projects Department is designed to support the successful delivery of complex infrastructure projects by bringing together a team of professionals with expertise and diverse, complementary skills. Hydro's Major Projects Management Team is comprised of Hydro employees, and is led by the Director, Major Projects and Asset Management and two Senior Managers who are collectively responsible for decision-making and project oversight. Role descriptions and an overview of each incumbent's qualifications are provided in Appendix C to this schedule.

Together, this team combines strategic leadership, operational excellence, and stakeholder engagement to deliver infrastructure projects efficiently and effectively. Their collective experience ensures that all aspects of project delivery are executed to the highest standards, meeting organizational goals and supporting long-term success.

7.3.2 Project Delivery Team

The successful execution of the BDE Unit 8 and Avalon CT projects relies on a team of dedicated professionals with the expertise and experience required to navigate its complexities. The Project Manager and Lead Engineer, supported by a skilled delivery team, bring the leadership, technical proficiency, and operational insight critical to addressing the unique challenges of these initiatives. Role descriptions and an overview of each incumbent's qualifications are provided in Appendix C to this schedule.

With their leadership and the support of a skilled delivery team, each project is guided by individuals who are not only experienced but also committed to ensuring every element is completed to the highest professional standard. Together, this team provides the vision, knowledge, and capability required to achieve project success and long-term value.

7.3.3 External Expertise

Hydro has partnered with leading engineering firms to ensure the successful execution of major capital projects. These external experts bring specialized knowledge, advanced technical capabilities, and strategic planning expertise to support the development of critical infrastructure.

AtkinsRéalis: BDE Unit 8 Project

AtkinsRéalis, a globally recognized engineering consulting firm, played a key role in delivering the FEED for the BDE Unit 8 project in 2024. With extensive experience in hydroelectric infrastructure, their multidisciplinary team developed designs tailored to the project's environmental and technical challenges. Their work provided a detailed cost estimate and set the foundation for efficient execution, ensuring long-term reliability and sustainability.

Beyond hydroelectric engineering, AtkinsRéalis integrated specialists in construction planning, risk assessment, and cost estimation to create a comprehensive FEED package. Their expertise in remote-site construction and financial forecasting allowed for a practical and well-informed project approach, positioning BDE Unit 8 as a crucial component in the province's future energy landscape.

Hatch: Avalon Combustion Turbine Project

Hatch, a leader in energy infrastructure and consulting, provided FEED for the Avalon CT project in 2024. Their team of experts in CT technology developed a design that maximizes efficiency, reduces environmental impact, and ensures operational flexibility to meet Newfoundland and Labrador's evolving energy needs.

In addition to technical expertise, Hatch incorporated specialists in construction management, risk mitigation, and cost estimation, ensuring a seamless transition from FEED to execution. Their strategic planning approach optimized site constraints while maintaining financial viability, making the Avalon CT project a key asset for strengthening the province's energy security and grid reliability.

8.0 Customer Rate Impact Analysis

Electricity rates are a concern for customers and rate pressure as a result of system expansion is a challenge that customers, utilities, and regulators in many other provinces and jurisdictions are facing. Many jurisdictions are dealing with the challenges associated with increased forecast demand and the resulting customer rate impact generation expansion will have on overall customer affordability of electricity.

The Government's rate mitigation plan provides clarity on Hydro's annual rate increases up to and including 2030. The Government has publicly committed to rate mitigation post-2030, but details on the structure and applicability of rate mitigation in that period remain under consideration, as do the longer-term rate forecasts for other regulated utilities across the country. As such, the impact to customer rates associated with the Avalon CT and BDE Unit 8 will not be fully known until further work evolves and concludes with the Government in the coming years before 2030.

Hydro will work with the Government 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.

Table 4 outlines the estimated incremental revenue requirement in the first full year in service associated with the Avalon CT and BDE Unit 8. The Planned Budget revenue requirement is provided in Appendix D to this schedule. The Authorized Budget estimates used for each project are consistent with those outlined in this application. The incremental revenue requirement has been calculated using Hydro's incremental weighted average cost of capital[63] and uses a composite depreciable life of 35 years for the Avalon CT and 60 years for BDE Unit 8.[64] The calculation is also inclusive of forecasted operating costs associated with both assets and forecasted fuel costs associated with the Avalon CT.[65] The incremental revenue requirement excludes the future reduction in Hydro's revenue requirement associated with the retirement of aging assets, namely the Holyrood TGS.

Table 4: Incremental Revenue Requirement ($ Million)

	Authorized Budget
Avalon CT	96.7
BDE Unit 8	83.3
Total	**180.0**

[63] Forecasted to be 5.80%.
[64] Useful life assumptions are consistent with those used in the analysis included in Hydro's 2024 Resource Adequacy Plan and 2024 Load Forecast.
[65] Revenue requirement estimates include operating costs for BDE Unit 8 and Avalon CT of $3.3 million and $3.7 million, respectively. As well, fuel costs of $16.6 million were included for the Avalon CT.

There are many factors that influence electricity rates, and it is important to note that no jurisdiction can predict, with certainty, where customer rates will be in 10 years. Hydro is actively seeking to mitigate rate pressures for customers wherever possible.

Factors that could influence customer rates over the next decade in our province include but are not limited to, rate impacts associated with Newfoundland Power costs and the Government's future decisions around rate mitigation in the post-2030 period. Hydro understands the levers that can drive customer rate impacts with respect to its generation expansion proposals and is doing everything possible to manage these impacts in a positive way for customers. Hydro is committed to making prudent investments, as necessary, to meet its legislative requirement to provide customers with service that is least-cost, reliable, and environmentally responsible.

9.0 Proposed Regulatory Reporting

Hydro proposes the implementation of a Major Projects quarterly report to the Board and Intervenors to provide an update on each project's scope, cost, schedule, risks, and any other relevant information that may arise throughout the time period. These reports will serve as a critical tool for stakeholder communication, risk mitigation, and informed decision-making, ensuring that project objectives remain aligned with expectations. By systematically evaluating budget performance, timeline adherence, evolving risks, and scope adjustments every three months, Hydro can proactively address potential challenges and optimize resource allocation. Additionally, these reports will incorporate any new insights, changes, or external factors that could impact project execution. Establishing a regular reporting cadence will enhance accountability, visibility, and adaptability, ultimately contributing to the project's overall success.

10.0 Conclusion

After a thorough examination of Hydro's recommendations through the 2024 Resource Adequacy Plan proceeding, Hydro refreshed its analysis and confirms that both the Avalon CT and BDE Unit 8 remain the least-cost, reliable, and environmentally responsible solutions. Hydro proposes to execute the construction of the two additional generation capacity options, Avalon CT and BDE Unit 8 to be completed in 2029 and 2031, respectively.

The planning, construction, and integration of new generating resources will take years, underscoring the need for expedient action to ensure adequate supply to meet the growing demand on the electrical system.

While the generation expansion plan is known, the associated project estimates are time sensitive and supply chain pressures continue to increase; therefore, any delay during the regulatory proceeding schedule or during project execution increases the risk of higher costs to ratepayers. Delays result in continued reliance on aging thermal assets and increased system reliability risk.

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.

The Authorized Budget for both projects, set at a P85 confidence level, balances cost efficiency with prudent risk management and is consistent with Justice LeBlanc's recommendations in the final report on the Muskrat Falls Inquiry. Hydro has assembled a qualified Major Projects Department that has the necessary expertise to execute these large-scale projects. Hydro is confident this team can successfully deliver BDE Unit 8 and the Avalon CT, utilizing a robust governance framework that reflects lessons learned from past projects, industry standards, and good utility practice.

Appendix A

Lessons Learned Overview

1.0 Lessons Learned

Hydro is committed to the application of lessons learned from the Muskrat Falls Inquiry, previous regulatory proceedings, and ensuring business continuity through a number of challenging circumstances, such as the COVID-19 pandemic.

1.1. Muskrat Falls Inquiry

The planning, execution, and transition to operations of the Muskrat Falls project provided Hydro with valuable lessons learned that have been implemented within the BDE Unit 8 and Avalon CT projects. In Justice LeBlanc's May 2020 final report, a series of key findings and recommendations were provided. Hydro has taken seriously its responsibility to ensure that the recommendations within its purview are reflected within the BDE Unit 8 and Avalon CT projects. Lessons learned reflect many key findings and recommendations from the Muskrat Falls Inquiry, such as:[1]

- Ensuring the Project Management Team, Hydro's Executive Leadership Team, and the Board of Directors have the appropriate competencies and experience to appropriately manage and oversee the projects.[2] Appendices B and C to Schedule 1 provide an overview of the qualifications of the Project Management Team, Hydro's Executive Leadership Team, and Hydro's Board of Directors.
- Establishing a governance framework that is founded on industry-accepted principles and standards. The governance framework provides for transparency in decision-making and multiple governing bodies with access to all information necessary to support risk-informed and evidence-based decision-making.[3]
- Robust evaluation of project alternatives through the *RRA Study Review*.[4]

[1] "Muskrat Falls: A Misguided Project, Commission of Inquiry Respecting the Muskrat Falls Project," The Honourable Richard D. LeBlanc, Commissioner, March 5, 2020, vol. I.
[2] *Supra,* f.n. 1, Key Findings 15, 16, 22, 30, and 55.
[3] *Supra,* f.n. 1, Key Findings 9, 17, 19, 23, 24, 25, 26, 44, 45, 46, 49, 50, 51, 57, 58, 59, and Key Recommendation 4.
[4] *Supra,* f.n. 1, Key Findings 2, 3, 31, 32, 33, 34, 35, 37, 54, and Key Recommendation 2.

- The Board of Commissioners of Public Utilities is providing independent review, approval, and oversight of the BDE Unit 8 and Avalon CT projects and Hydro is committed to fully supporting, and cooperating with, the regulatory process.[5]
- Both the BDE Unit 8 and Avalon CT project estimates reflect a probability value of P85.[6] The cost and schedule estimates contemplate contingency and management reserves that are appropriate in consideration of the tactical and strategic risks associated with each project.[7]
- Both project budgets are based on AACE Class 3 cost estimates and were developed using generally accepted industry practice.[8]
- Hydro's phased approval process provides for multiple decision points that require reassessment and justification of the business case, preventing premature sanction decisions and continuation of previously approved projects if they no longer make business sense.[9]
- The Project Management Team will have a more frequent and visible on-site presence through the construction manager who will be on-site full-time and regular visits by the Project Manager, engineers, safety, etc.[10]
- The projects will adopt many procurement policies and procedures that were used on the Muskrat Falls project, which were found to have met best practice standards.[11]
- Hydro is ensuring there are regular, documented updates from Hydro to the provincial government throughout project planning, execution, and delivery.[12]

1.2. Previous Regulatory Proceedings

Hydro has applied lessons learned from historical regulatory proceedings in its applications for approval of the BDE Unit 8 and Avalon CT projects.

[5] *Supra,* f.n. 1, Key Findings 6, 27, 61, 63, 64, 65, 66, 67, 68, 69, and Key Recommendations 1 and 2.
[6] *Supra,* f.n. 1, Key Recommendation 5.
[7] *Supra,* f.n. 1, Key Findings 39, 40, 41, and 42.
[8] *Supra,* f.n. 1, Key Findings 39 and 52.
[9] *Supra,* f.n. 1, Key Findings 10 and 38.
[10] *Supra,* f.n. 1, Key Findings 20 and 21.
[11] *Supra,* f.n. 1, Key Finding 29.
[12] *Supra,* f.n. 1, Key Findings 23, 24, 26, 44, and Key Recommendation 15.

- Hydro's *RRA Study Review* provides for proactive evaluation of adequacy and reliability of supply on the Island Interconnected System.[13]
- Consideration of customer impact and customer perspective in Hydro's decision-making through the *RRA Study Review*, which identified the BDE Unit 8 and Avalon CT projects as the least-cost, technically viable projects to advance at this time.[14]
- Application of risk management practices throughout project planning, execution, and delivery, including consideration of ongoing operational requirements and alignment with Hydro's corporate enterprise risk management process.[15]

1.3. Business Continuity

In the past five years, Hydro has demonstrated its agility in responding to significant, impactful changes to its operating environment. Hydro has been able to continue its core operations through major weather events, wildfires, and a global pandemic. Hydro's experiences through these events have provided the opportunity to test its emergency preparedness, the resilience of its infrastructure, and its proactive risk management practices. Hydro's performance through each of these unique events has proven that the application of lessons learned contributes in a meaningful way to Hydro's continual improvement and its ability to continue its core business operations during challenging circumstances.

[13] "Investigation and Hearing into Supply Issues and Power Outages on the Island Interconnected System, Phase One Report," Board of Commissioners of Public Utilities, September 29, 2016, p. i.
[14] *Supra*, f.n. 13, app. A, p. 10 of 11.
[15] *Supra,* f.n. 13, p. 26

Appendix B

Governing Bodies Overview

1.0 Governing Bodies

Hydro's governing bodies, as outlined in the Major Projects Governance Framework, are composed of seasoned professionals with extensive experience across a wide range of industries and disciplines. The groups bring a wealth of expertise from leadership roles in Boards of Directors, industry working groups, and professional associations. With diverse backgrounds in governance, finance, law, engineering, policy, and organizational effectiveness, they offer strategic oversight and ensure alignment with Hydro's strategies. Their collective experience across sectors—including utilities, law, academia, government, and non-profits—provides invaluable insights, enabling them to assess Major Projects effectively, apply lessons learned, and drive impactful decisions. Together, they deliver the knowledge and competencies necessary for strong governance and meaningful value creation.

Hydro's Board of Directors

Hydro's Board of Directors is comprised of thirteen members, including Hydro's President and CEO. The Board of Directors has a diverse range of backgrounds, including legal, talent management and employee relations, organizational effectiveness, labour relations, business and finance, engineering, accounting, education, policy development, strategy, etc. The Board of Directors has experience across many sectors, including utility, commercial law, academia, government, not-for-profit, etc. They have all occupied senior leadership positions and have participated in numerous Boards of Directors, industry working groups, and professional associations. Their collective education, work experience, and volunteer experience have provided them with invaluable knowledge and the necessary competencies to provide robust oversight of all of Hydro's business, including utility planning and Major Projects. More detailed information on Hydro's Board of Directors can be viewed on Hydro's website.[1]

Reliability and Resource Adequacy and Major Projects Committee

Three of the committee members spent the majority of their careers working at Hydro in engineering and leadership roles and were directly involved in many aspects of planning, design, construction, maintenance, and monitoring of Hydro's generating facilities and major structures and have first-hand experience in large-scale projects undertaken by Hydro, project management roles. They have a wealth

[1] https://nlhydro.com/about-us/leadership-team-and-board/

of first-hand knowledge of Hydro’s electrical system and a deep understanding of its assets and operational requirements. The fourth Committee member has a business and finance background and has held senior roles within the provincial government and telecommunications sector. Among other things, their experience includes commercial negotiations and project finance. All four directors have served on various Boards of Directors, industry working groups, and professional associations. Their extensive experience with Hydro, technical knowledge, and business acumen position them to provide meaningful oversight to Hydro’s Major Projects through all project phases.

Hydro’s Executive Leadership Team

Hydro’s Executive Leadership Team is comprised of Hydro’s President and CEO and eight Vice Presidents who represent all areas of Hydro’s business. Hydro’s President and CEO is a professional engineer who has spent much of her career working in the utility industry, including more than ten years working for Hydro. Hydro’s Vice Presidents include professionals with backgrounds in legal, corporate strategy, employee relations, accounting and finance, project management, engineering, regulatory affairs, public relations, etc. The Executive Leadership Team has extensive utility experience and is committed to continuous improvement, living Hydro’s values, and leading Hydro in a manner that meets the public’s expectations of a crown utility.

Appendix C

Major Projects Team Overview

1.0 Major Projects Organization

The Major Projects functional organizational chart is depicted in Figure B-1. The department is composed of the Management Team and the individual Project Delivery Teams.

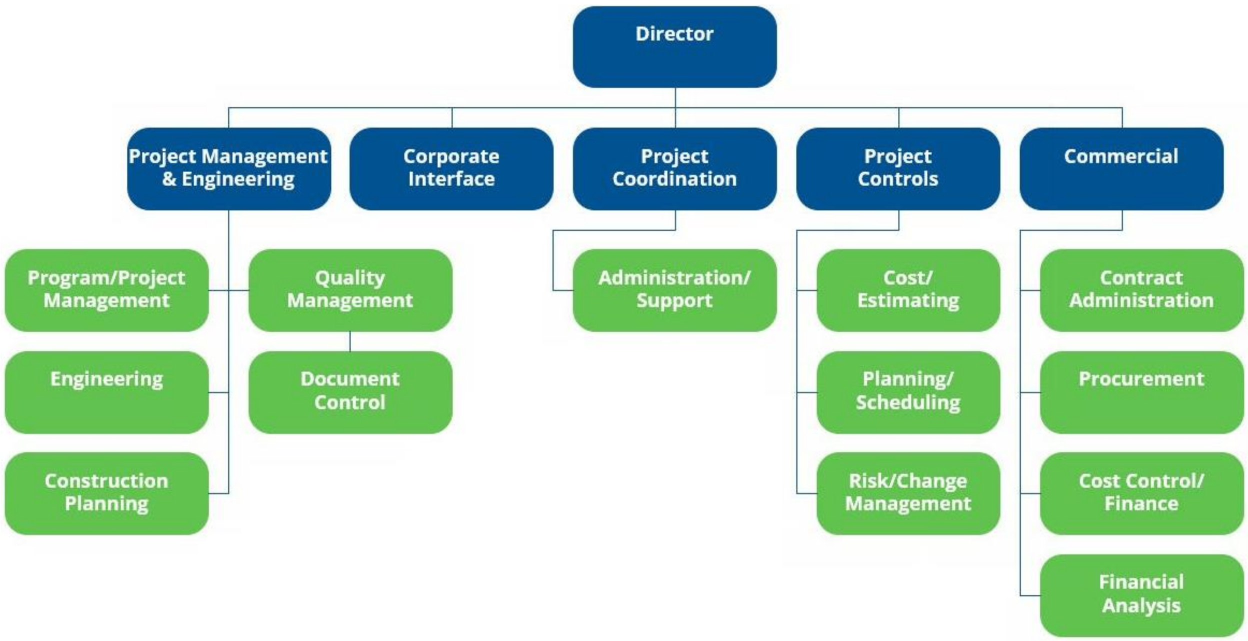

Figure B-1: Major Projects Organization

1.1. Major Projects Management Team

The Director of Major Projects and Asset Management leads the team with over 25 years of experience driving high-value initiatives, including major energy infrastructure development and the establishment of a dedicated department for executing major projects. This role provides strategic direction, ensuring the alignment of project objectives with organizational priorities while overseeing critical investments such as hydroelectric upgrades, system impact studies, and transmission infrastructure expansion. As a Professional Engineer with a background in Chemical Engineering and extensive experience in regulated capital investment strategies and execution plans, they bring a strategic and technical perspective to the successful execution of complex infrastructure projects.

Supporting this leadership, the Senior Manager for Major Projects Project Management and Engineering brings over 18 years of experience in utility-scale project delivery, overseeing planning, project management, and engineering for large-scale infrastructure initiatives. Beginning their career as a civil transmission engineer, this individual played a key role in the design and development of transmission infrastructure as part of the Lower Churchill Project and has since held roles of increasing responsibility, including engineering manager and project manager for multi-million and billion-dollar projects. Their comprehensive experience includes planning, design, implementation, and operation of major utility infrastructure, as well as managing engineering and capital planning for complex projects.

This role also leads a dedicated team of professionals specializing in program and project management, engineering, quality assurance, construction planning, and document control, disciplines critical to ensuring every phase of project execution is managed and aligned with strategic objectives.

The Senior Manager, Commercial, brings over 24 years of experience in financial management, procurement, and contract administration, including 14 years with Hydro. This role encompasses overseeing commercial agreements, negotiating complex contracts, and maintaining financial controls for large utility initiatives. Their experience includes restructuring multi-billion-dollar financing arrangements, managing contract close-outs, and ensuring the completion of commissioning obligations on major energy projects such as the Lower Churchill Project. Additionally, their work in dispute resolution, process development, and the administration of civil works and EPCM contracts ensures effective financial oversight and risk mitigation, essential for the successful execution of large-scale infrastructure initiatives.

The Manager of Major Projects Corporate Interface brings over a decade of experience in regulatory compliance, stakeholder engagement, and cross-functional collaboration. This role is essential in ensuring seamless communication and alignment between corporate goals and project requirements, fostering strong relationships with internal stakeholders, and driving effective decision-making. This individual has held roles of progressive responsibility including Regulatory Project Manager and Senior Supervisor of Regulatory Policy and Compliance within Hydro's Regulatory Affairs department. Their expertise in managing complex regulatory processes, developing compliance frameworks, and aligning corporate objectives with stakeholder priorities supports the smooth and efficient execution of major initiatives.

Supporting a culture of safety, the Safety Advisor, with decades of experience in health, safety, and environmental management, develops and implements comprehensive safety programs tailored to complex project environments. Their background includes leading Health Safety Environment and Quality (HSEQ) systems across offshore oil and gas, large-scale construction, and industrial operations. Notable roles include serving as HSEQ Advisor during the Hebron Gravity Base construction, where they coordinated safety practices across construction, marine, and engineering teams, and managing safety and permitting systems for the commissioning phase of the Lower Churchill Project. With expertise in hazard identification, regulatory compliance, and contractor safety performance, they are instrumental in ensuring a safe and efficient project environment.

The Manager of Project Controls, with more than 25 years of expertise in planning, scheduling, and risk management, plays a critical role in maintaining project timelines, optimizing contractor performance, and managing resources effectively. This individual has extensive experience across industries, including renewable energy, oil and gas, and hydroelectric projects, developing and implementing project control systems that ensure precise execution. They have successfully led re-baselining efforts for major projects, analyzed and optimized contractor schedules, and introduced enhanced reporting frameworks to support decision-making. Additionally, their expertise in mitigating delays and proactively addressing disputes has been instrumental in maintaining project alignment with strategic objectives.

Overseeing key functions such as cost estimating, planning, and risk/change management, this role integrates these critical processes to ensure accurate budgeting, coordinated scheduling, and effective risk mitigation. Together, these functions provide the structure and insights necessary to address challenges, align project execution with strategic goals, and support the efficient delivery of complex infrastructure projects.

The Project Coordinator supports Major Capital Projects by managing logistics, tracking milestones, and ensuring seamless coordination across teams. With experience on large-scale projects such as the Long Harbour Nickel Processing Plant, Voisey's Bay Mine, and Bay d'Espoir–Avalon transmission upgrades, they specialize in project administration, document control, and stakeholder reporting. Proficient in platforms like SharePoint and Aconex, they enhance workflow efficiency while maintaining compliance with regulatory and safety standards.

The Stakeholder Relations Lead brings over 20 years of experience in communications, stakeholder engagement, and government relations. With a decade at Hydro, they have guided stakeholder strategies for major projects, ensuring strong partnerships and public trust. Their expertise includes policy development, change management, and corporate communications, aligning projects with community and organizational priorities.

1.2. Project Delivery Teams

1.2.1 BDE Unit 8

The Project Manager, a Professional Engineer with 25 years of experience, has led a wide range of multi-disciplinary utility and industrial projects. Starting as a civil/structural engineer, their career evolved into managing large-scale utility and infrastructure projects, where they consistently delivered results by balancing safety, schedule adherence, budget control, and stakeholder satisfaction. Their portfolio includes FEP and design for hydroelectric developments, the construction of 230 kV and 138 kV terminal stations and transmission lines, and the fast-track installation of the Holyrood CT. In addition, they have played key roles as an assistant site representative for a 40 MW hydroelectric project and as the Project Manager for major industrial facility infrastructure designs. These roles required thorough planning, coordination across diverse teams, and the ability to navigate complex technical and operational challenges.

The Lead Engineer, with over 20 years of experience in mechanical engineering, specializes in power generation and mission-critical projects. Their career began in commercial building design before transitioning to heavy industrial systems and, ultimately, power generation, where they have built an exceptional track record in engineering leadership. Their extensive experience includes managing the engineering design and front-end execution planning for new generating units at the Bay d'Espoir Generating Station, as well as overseeing turbine refurbishments and condition assessments. They have also developed long-term capital plans for hydroelectric systems, led structural upgrades, and executed rotor and turbine replacements at several generating stations. In the thermal power sector, their expertise spans life extension studies, turbine overhauls, and digital control system upgrades. These achievements highlight their ability to tackle technical challenges, optimize performance, and ensure system reliability.

The combined experience and expertise of the Project Manager and Lead Engineer form a strong foundation for project delivery, ensuring all critical aspects of planning, design, and execution are meticulously managed. Their leadership is complemented by a focus on innovation, stakeholder

Appendix D

Planned Project Budget Rate Impact Analysis

Redacted

Schedule 1
Attachment 1

Schedule 1, Attachment 1

Governance Framework

Major Projects

Governance Framework

NLH Doc. No. NLH-MPM-00000-PM-STG-0001-01

Comments: The Major Projects Governance Framework establishes Hydro's approach to the governance of major projects, ensures alignment between the governance of major projects and existing corporate governance structures and processes, establishes the role and function of the Major Projects Department, and establishes appropriate frameworks for governing bodies to ensure appropriate approvals and oversight are achieved during all phases of project planning, execution, and delivery of major projects.	**Total # of Pages (including Cover): 65**
Revision B0 was Approved by Newfoundland and Labrador Hydro's Board of Directors on February 25, 2025	

B0	5-Mar-2025	Use	Ann Malone	Gail Randell	Robert Collett	Jennifer Williams
Revision	**Date** (DD-MMM-YYYY)	**Issue Reason**	**Prepared By** Lead, Strategic Initiatives	**Approved By** Director, Major Projects & Asset Management	**Approved by** Vice President, Hydro Engineering & NLSO	**Approved by** President & CEO
These signatures are required to confirm compliance with Major Projects Department procedures. This document cannot be finalized or distributed without this approval. Any version of this document without these signatures is not considered final.						

Contents

List of Attachments

1.0 Introduction

Newfoundland and Labrador Hydro (Hydro) provides an essential service to the people of Newfoundland and Labrador, one that is critical to the province's economy. Hydro has a legislated obligation to provide power at the lowest possible cost consistent with reliable service in an environmentally responsible manner.[1] Beyond its own mandate, as a Crown utility, Hydro must also support the development and implementation of the Government of Newfoundland and Labrador's policies as applicable or directed.

To meet the increasing demand for reliable energy in the province, it is prudent and necessary for Hydro to make substantive investments in the provincial electrical grid. Hydro must undertake major projects and programs (major projects)[2] to:

- Support the continued safe and reliable operation of Hydro's existing electrical infrastructure; and
- Develop and integrate new assets, to increase the amount of energy and capacity available to serve Hydro's customers.

Major projects are necessary to enable Hydro to fulfil its legislated requirement of meeting provincial electricity needs and support provincial climate and energy policies. However, with major projects come substantial risks and opportunities for Hydro and its customers, as well as the Government of Newfoundland and Labrador (the provincial government) and the citizens of the province. It is therefore critical that Hydro implements appropriate governance structures and processes to ensure these investments are appropriately justified, planned, authorized, and managed through the execution and delivery of major projects.

1.1 Corporate vs. Project Governance

Corporate governance is a term that refers broadly to the laws, rules, and processes by which businesses are operated, managed, regulated, and controlled. Well-defined and enforced corporate governance provides a structure that works for the benefit of all stakeholders by ensuring that the organization adheres to accepted standards and best practices as well as to formal laws and regulations.

This Major Projects Governance Framework (Governance Framework) extends the principles of corporate governance into Hydro's management and oversight of major project activities and provides additional measures to promote generally accepted practices in the governance of large capital projects. It is not intended to duplicate or replace Hydro's existing corporate governance standards or practices; rather, it provides the necessary level of governance clarity required to successfully plan, execute, and deliver major projects in accordance with Hydro's mandate, values, and strategic goals.

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[1] *Electrical Power Control Act, 1994*, SNL 1994, c E-5.1, s 3(b)(iii).
[2] For the purposes of this document, the term 'major project' is generally used to describe regulated projects and programs with an anticipated cost of $50 million or greater under the accountability of the Major Projects Department.

2.0 Purpose

The purpose of this Governance Framework is to:

- Establish Hydro's approach to the governance of major projects;
- Ensure alignment between the governance of major projects and existing corporate governance structures and processes;
- Establish the role and function of the Major Projects Department;[3] and
- Establish appropriate frameworks for governing bodies to ensure appropriate approvals and oversight are achieved during all phases of project planning, execution, and delivery of major projects.

As Hydro progresses through the various stages of major projects and elements of this work become embedded in Hydro's day-to-day operations, this Governance Framework may evolve to appropriately reflect the level of governance required at that point in time.

3.0 Scope and Applicability of Governance Framework

3.1 Document Scope

This Governance Framework is generally applicable to all regulated projects and programs with an anticipated cost of $50 million or greater[4] under the accountability of the Major Projects Department. Project complexity, which is further addressed in Section 3.2, is also taken into consideration in determining whether a project or program is considered a major project and therefore subject to this Governance Framework.

This Governance Framework is intended to articulate Hydro's philosophy on major projects and establish the appropriate frameworks for governing bodies and structures that will guide decision-making, authorizations, compliance, and oversight of major projects throughout their life cycle.

The scope of this Governance Framework is limited to Hydro's internal governance of major projects. However, as a Crown utility, Hydro is committed to compliance with any additional governance requirements that may be set out by the provincial government, the Board of Commissioners of Public Utilities (Public Utilities Board), or any other external bodies to which it may be legislatively or contractually accountable throughout the course of planning, executing, and delivering major projects.

3.2 Governance and Project Complexity

Governance of major projects will be reflective of the complexity of each specific major project. Each major project will undergo a complexity assessment that will inform the governance effort that is most appropriate for that major project.

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[3] An overview of the Major Projects Department is provided in Section 6.0.
[4] Based on an AACE (Association for the Advancement of Cost Engineering International) Class 5 estimate (includes Contingency but does not include Management Reserve).

Complexity is defined as a "characteristic of a program or project or its environment which is difficult to manage due to human behaviour, system behaviour, or ambiguity."[5] Major projects with higher complexity will require higher governance authority structure, resources, and processes. When there is a lower level of rigour in governance processes than required, risk is introduced. However, when there is a higher level of rigour in governance processes than required, inefficiency results.[6] In the context of Hydro's role as a Crown utility, an excess of either risk or inefficiency can result in delays, increased costs, and other undesirable outcomes that are not in alignment with Hydro's legislative mandate, vision, values, or strategic goals. Therefore, Hydro is taking a project-by-project approach to governance to ensure an appropriate assessment of complexity to determine the level of governance that best balances risk and efficiency. Figure 1 illustrates the relationship between governance and complexity.

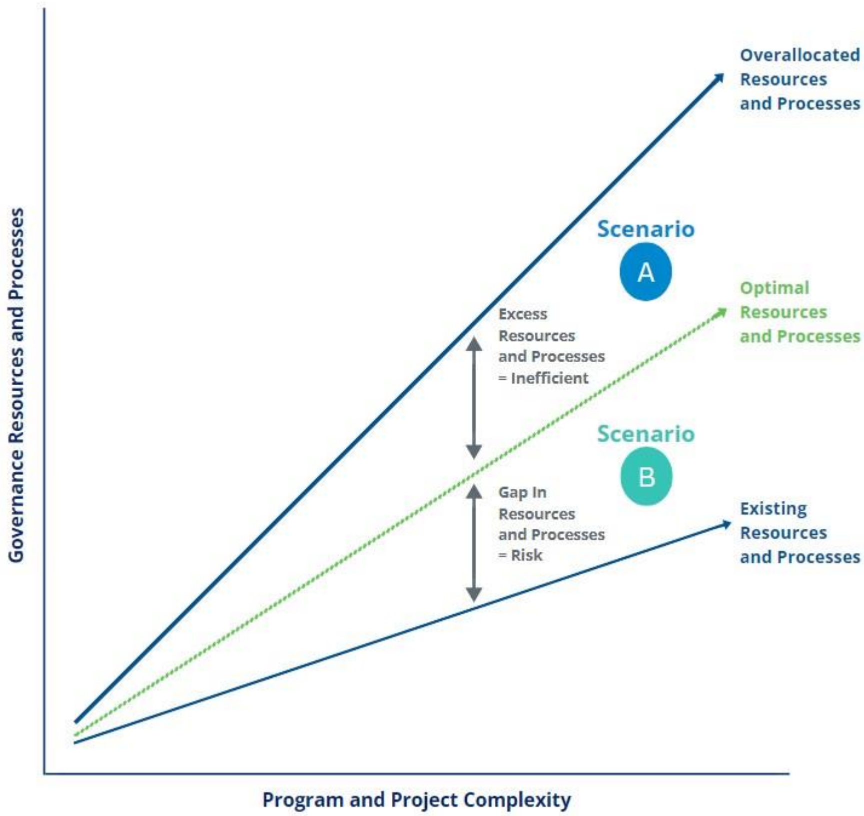

Figure 1: Governance Required Increases with Program and Project Complexity

[5] *Governance of Portfolios, Programs, and Projects: A Practice Guide*, Project Management Institute, 2016, p. 7.
[6] *Governance of Portfolios, Programs, and Projects: A Practice Guide*, Project Management Institute, 2016, p. 8.

To determine the complexity of major projects, Hydro's Internal Audit & Advisory Services Department facilitates a complexity assessment. The complexity assessment includes a questionnaire obtained from the Project Management Institute's Navigating Complexity Practice Guide.[7] The 48 questions assess the three core categories of complexity:

1. **Human behaviour**: Considers individual behaviours (e.g., biases, resistance, etc.); group/organizational/political behaviour (e.g., groupthink, self-organization, stakeholder commitment, etc.); communication and control (e.g., varying legal perspectives, cultural diversity, etc.); and organizational design and development (e.g., misalignment, opacity, etc.).
2. **System behaviour**: Considers connectedness (e.g., multiple systems such as regulatory agencies, consultants, subcontractors, local communities, etc.); dependency (e.g., dependency between project and its operating environment, dependency between projects, etc.); and the dynamics of the various systems (e.g., criticality and turnover of key personnel, environmental changes such as changing political agendas, etc.).[8]
3. **Ambiguity:** Considers uncertainty (i.e., the degree to which certain project elements are unknown) and emergence (i.e., spontaneous or gradual unanticipated change).

For each major project, the Internal Audit & Advisory Services Department also facilitates the completion of a complexity assessment that is modelled based on the Project Management Institute's Navigating Complexity Practice Guide. The complexity assessment assigns a score to various elements of complexity and, based on that score, a major project's scale (e.g., large, major, or mega project) and complexity (e.g., high, very high, extreme) are ranked. Based on the ranking, the complexity assessment tool output also includes a list of major project governance deliverables that are required to successfully execute the major project or a governance/management to-do list. The number of deliverables (i.e., effort) required increases with the complexity of the major project. In essence, the larger the major project scale and complexity, the greater the level of governance required.

Typically, regulated major projects greater than $50 million that are under the accountability of the Major Projects Department will range from large major projects with a high level of complexity to mega projects with an extreme level of complexity. For this reason, Hydro is prioritizing governance in all phases of planning, execution, and delivery of major projects.

[7] *Navigating Complexity: A Practice Guide*, Project Management Institute, 2014.
[8] A system is a collection of different components that together can produce results not obtainable by the components alone.

4.0 Reference Documents

Table 1 outlines the documents that complement and support this Governance Framework.

Table 1: Reference Documents

Title	Reference
Corporate Documentation	
Code of Business Conduct and Business Ethics	ER-001
Environmental Management System Policy	EN-002
Hydro Policy Management Policy	PO-001
Occupational Health and Safety Policy	SH-001
Signing Authorities Policy	FIN-012
External Documentation	
Access to Information and Protection of Privacy Act, 2015[9]	n/a
Electrical Power Control Act, 1994[10]	n/a
Hydro Corporation Act, 2024[11]	n/a
Management of Information Act[12]	n/a
Occupational Health and Safety Act[13]	n/a
Public Procurement Act[14]	n/a
Public Utilities Act[15]	n/a
Capital Budget Application Guidelines[16]	n/a
Major Projects Department Documentation	
Major Projects Change Management Plan	NLH-MPM-00000-PC-PLN-0001-01
Major Projects Engineering Management Strategy	NLH-MPM-00000-EN-STG-0001-01
Major Projects Information Management Plan	NLH-MPM-00000-IM-PLN-0001-01
Major Projects Overarching Contracting Strategy	NLH-MPM-00000-PO-STG-0002-01
Major Projects Procurement Management Plan	NLH-MPM-00000-PO-PLN-0001-01
Major Projects Project Controls Strategy	NLH-MPM-00000-PC-STG-0001-01
Major Projects Project/Program Management Strategy	NLH-MPM-00000-PM-STG-0002-01
Major Projects Quality Management Strategy	NLH-MPM-00000-QM-STG-0001-01
Major Projects Risk Management Strategy	NLH-MPM-00000-RM-STG-0001-01
Major Projects Safety & Health Management Strategy	NLH-MPM-00000-HS-STG-0001-01

[9] *Access to Information and Protection of Privacy Act, 2015,* SNL 2015, c A-1.2.
[10] *Electrical Power Control Act, 1994*, SNL 1994, c E-5.1.
[11] *Hydro Corporation Act, 2024*, SNL 2024, c H-18.
[12] *Management of Information Act*, SNL 2005, c M-1.01.
[13] *Occupational Health and Safety Act*, RSNL 1990, c O-3.
[14] *Public Procurement Act*, SNL 2016 c P-41.001.
[15] *Public Utilities Act*, RSNL 1994, c P-47.
[16] "Capital Budget Application Guidelines (Provisional)," Board of Commissioners of Public Utilities, January 2022.

5.0 Hydro's Approach to Governance of Major Projects

Major projects have some attributes, risks, and opportunities that differ from Hydro's core utility business. As such, major projects have additional oversight requirements to ensure that these projects and programs:

- Are planned, executed, and delivered in a manner that aligns with Hydro's legislated mandate, vision, values, and corporate strategic goals; and
- Deliver the intended value to Hydro, its customers, and the province.

Hydro's governance of major projects is considerate of its role as a Crown utility, including the expectations of its customers and the province (e.g., legal and regulatory compliance, stewardship of public funds, prudent risk management, and ethical conduct). Hydro's approach to governance also contemplates lessons learned from prior projects and regulatory proceedings as well as generally accepted industry practice. Finally, the major projects governance approach ensures alignment and integration with Hydro's existing corporate governance structure.

Hydro has based this Governance Framework on industry guidance from the Project Management Institute, the Institute of Internal Auditors, and the Association for the Advancement of Cost Engineering International (AACE).

5.1 Corporate Alignment

5.1.1 Legislated Mandate

Among other things, provincial legislation essentially renders Hydro responsible for the provision of electricity within Newfoundland and Labrador[17] and development of provincial energy resources in a manner that supports the economic prosperity of Newfoundland and Labrador. Hydro will govern major projects in a manner that ensures they remain in alignment with Hydro's legislated mandate.

5.1.2 Vision and Values

Major projects must align with Hydro's corporate vision. Employees and contractors working on major projects are expected to conduct themselves in a manner that is consistent with Hydro's corporate vision and values.[18]

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.

-Hydro's Vision

[17] *Hydro Corporation Act, 2024*, SNL 2024, c H-18, s 14(1).
[18] "Our Values" Newfoundland and Labrador Hydro.
<https://nlhydro.com/about-us/our-commitments/our-values/>

We are safe.

- We don't compromise when it comes to the safety and well-being of our employees and customers. Every one of us shares the responsibility of making sure we go home safely at the end of the day.

We are committed.

- Our dedicated people are our greatest strength. We bring passion, expertise, integrity, and perseverance to everything we do.

We are inclusive and collaborative.

- We seek diversity and understand its value. We work together, listen to each other, and serve with respect.

We are forward-thinking.

- We find solutions, embrace ideas, test our decision making, and face challenges head-on to find a path forward together—all to deliver a sustainable future.

We are community-focused.

- We serve our neighbours, family, and friends in every part of the province. We give back, work hard, and power lives, businesses, and industries.

Figure 2: Hydro's Values

5.1.3 Strategic Goals

Major projects undertaken by Hydro will contribute in a meaningful way to Hydro's corporate strategic goals. Table 2 summarizes the goals outlined in Hydro's 2023–2025 Strategic Plan,[19] as well as how major projects will contribute to each goal.

Table 2: Major Projects' Contributions to Hydro's 2023–2025 Strategic Goals

Goal	Major Projects' Contribution
Goal 1: Revitalize our Organization	Major projects will promote cost-consciousness and accountability, prepare for future system requirements, support provincial power policy and legislation, make efficient use of the electrical system and resources, and apply governance practices to ensure efficient and effective oversight.

[19] "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>

Goal	Major Projects' Contribution
Goal 2: Deliver Reliable Electricity to our Customers at the Lowest Possible Cost	Major projects will use sound asset management planning principles to ensure its decision-making processes integrate a balance of risk, performance, and cost, and to make measured and responsible capital investments.
Goal 3: Recognize Indigenous History and Strengthen Indigenous Relationships	Major projects will undertake engagement activities and contribute to Hydro's efforts to strengthen relationships with Indigenous Peoples and communities.
Goal 4: Engage Who We Serve	Major projects will engage in open and regular communication with stakeholders and incorporate feedback into its operations, as appropriate.
Goal 5: Continue to Prioritize the Safety and Health of our Employees	Major projects will promote Hydro's safety and health culture and provide appropriate training, tools, and support.
Goal 6: Foster Proud and Engaged Teams	Major projects will engage and integrate employees across Hydro to provide development opportunities and cultivate a culture of open communication, learning, embracing diversity, and promoting equity and inclusion. Contractors will operate as part of Hydro's team to share their expertise and support Hydro's culture.
Goal 7: Anticipate and Develop our Workforce Requirements	Major projects will support the growth and retention of the expertise needed to support major projects, including their ongoing operation and maintenance, within the organization for the long term.
Goal 8: Support Growth of Renewable Energy Supply	Major projects will ensure potential renewable development opportunities are evaluated as appropriate and will promote responsible growth of the renewable energy industry.
Goal 9: Advance Electrification and Demand Management	Major projects are necessary to ensure the provincial electrical system's ability to enable electrification in the province.
Goal 10: Optimize the Value of Provincial Energy Resources	Major projects are necessary to ensure the provincial electrical system's ability to support growth from industrial and commercial customers, in turn growing our local economy.
Goal 11: Integrate Renewable Energy Resources in Local Communities	Major projects in rural and isolated parts of the province will support (where possible) Indigenous governments, Indigenous organizations, and local communities with the development and integration of renewable energy.

5.1.4 Corporate Policies and Standards

Major projects will adhere to Hydro's corporate policies and standards. In instances where a policy or standard does not exist within Hydro or it is not deemed to reflect the differences between major projects' requirements and those of Hydro, the Major Projects Department's Management Team will identify this deficiency with the Major Projects Steering Committee (further discussed in Section 8.7) and propose a solution. New policies created or amendments to existing policies will follow Hydro's established protocol for approval prior to implementation, as defined in the Hydro Policy Management Policy (PO-001).

5.2 Expectations of a Crown Utility

As a Crown utility, Hydro must ensure it has adequate infrastructure in place to meet existing and provincial supply needs. Hydro is also obligated to ensure that its infrastructure is properly maintained and operated to ensure safe and reliable service that is consistent with Good Utility Practice. Hydro's role as a Crown utility also informs its approach to undertaking major projects from a customer, legal, regulatory, cost, and risk perspective.

5.2.1 Customer Consideration

As is the case with the rest of its business, Hydro makes decisions related to major projects in consideration of the views of, and potential impact on, its customers. Hydro's customers have been consulted through the *Reliability and Resource Adequacy Study Review* (RRA) proceeding to collect their feedback related to reliability, cost, investment, growth, clean energy, and options for new sources of electricity.[20,21] Hydro recognizes that its customers are burdened by the increasing cost of living and are sensitive to rate increases. The feedback Hydro receives from customer engagement activities is one of Hydro's key considerations when selecting which projects to pursue to ensure customers receive the safe, reliable, cost-conscious, and environmentally responsible service they expect of Hydro.

5.2.2 Legislation, Permitting, Licensing, and Approvals

Hydro is subject to the provisions of the *Hydro Corporation Act, 2024*, the *Public Utilities Act*, and the *Electrical Power Control Act, 1994*, which, among other things, establish Hydro as a crown utility, define the Public Utility Board's authority as a regulator, and establish the provincial power policy. Hydro is also subject to legislation related to labour relations, safety and health, the environment, public procurement, information management, access to information and protection of privacy, consultation of Indigenous Peoples, transparency and accountability, etc. While this is not an exhaustive list and the applicability of certain pieces of legislation may vary from project to project, consistent with how the broader Hydro organization operates, Hydro's approach to major projects takes into consideration the

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[20] The most recent engagement was a January 2024 digital public engagement survey administered by a third-party research partner, where more than 2,000 responses were received. Hydro applied research methods consistent with engagement activities used by other utilities across Canada. Hydro's approach followed International Association for Public Participation (IAP2) principles.

[21] "What Was Said Report – 2024 Public Engagement – Reliability and Resource Adequacy Study Review," Newfoundland and Labrador Hydro, 2024.
<https://nlhydro.com/wp-content/uploads/2024/07/Final_2024-RAP_App-D_Engagement.pdf>

requirement to comply with applicable legislative and regulatory constraints, as well as obtain all necessary permits, licenses, and approvals.

5.2.3 Regulatory Compliance

Hydro is regulated by the Public Utilities Board, the regulatory body responsible for the general supervision of electric utilities and has broad legislated powers and responsibilities. Hydro is required to obtain approval of its capital expenditures from the Public Utilities Board, including major projects, unless the expenditures are otherwise legislatively exempt.

Prior to undertaking regulated major projects, Hydro is required to file an application for capital expenditure in accordance with the Capital Budget Guidelines established by the Public Utilities Board. The Capital Budget Guidelines outline the format and content of capital expenditure applications as well as a high-level description of the process, procedures, and timelines for the review of such applications. For major capital expenditures that may have significant implications for the electricity system, customers, or the utility, the Public Utilities Board may determine that there should be a separate process to address the proposal. Hydro must adhere to the steps and schedule established by the Public Utilities Board for the regulatory proceeding to evaluate Hydro's application. Once approved, the Public Utilities Board may impose additional reporting requirements throughout the project that may include providing updates on matters including, but not limited to, cost, schedule, and scope.

Hydro's approach to major projects must consider the Public Utilities Board as a key stakeholder and its role in reviewing, approving, and overseeing major projects. Hydro must factor the regulatory approval process into its resourcing, planning, and scheduling.

5.2.4 Stewardship of Public Funds

Hydro's approach to major projects takes into account the fact that it is expending public money. Taking into consideration public and customer feedback, a robust understanding of system needs, provincial policy, and the province's renewable resources as a potential catalyst for sustainable economic growth, Hydro will endeavour to appropriately balance cost, reliability, and environmental considerations when pursuing major projects.

5.2.5 Prudent Risk Management

The Major Projects Department will generally assume a low to moderate risk appetite. This is reflective of Hydro's role as a Crown utility and its legislative requirements to prioritize safety, the environment, reliability, and cost consciousness in conducting its business, including the planning, execution, and delivery of major projects. The Major Projects Department will implement a risk management strategy that prioritizes early identification of risk, enabling proactive risk management and continuous risk evaluation throughout all project phases. This approach supports informed decision-making, the development of project budgets, stakeholder management, and other areas critical to major projects success. Section 12.0 provides further information about risk management, including alignment with Hydro's existing Enterprise Risk Management (ERM) program.

As the Major Projects Department matures and Hydro gains additional experience with major projects, Hydro will continue to mature its risk management process, including defining the risk appetite, tolerance, and threshold for each risk category. The goal of this exercise will be to clearly and transparently define the operating parameters and further inform decision-making with respect to Hydro's assumption of risk in planning, executing, and delivering major projects.

5.2.6 Ethical Conduct

Representatives of Hydro, whether employees or contractors, including those employed to work on major projects, are subject to Hydro's Code of Conduct and Business Ethics (the Code).[22] The Code outlines four key principles that guide the day-to-day work of Hydro's employees and contractors:

1. The commercial, reputational, and other interests of Hydro must always take precedence over personal interests and those of third parties.
2. We must always avoid any act or conduct—intentional or not—that may support the private interests of a third party or an individual over those of Hydro.
3. Any conflict of interest—real or perceived—has the potential to impair the company's credibility, reputation, and commercial interests.
4. We have an obligation to perform our duties and responsibilities in a conscientious manner, and never allow our personal interests to conflict with those of Hydro.

The Code also outlines requirements related to a respectful workplace, protecting Hydro's business (including its assets and information), and conflicts of interest.

5.3 Application of Lessons Learned

Hydro's governance approach will embed the application of lessons learned from previous projects and regulatory proceedings to ensure continual improvement. This includes, but is not limited to, the following:

- Undertaking major projects within the existing Hydro corporate structure rather than segregating into a separate organizational structure.
- Proactive system planning and asset management.
- Consideration of operability, maintainability, and total life cycle cost throughout all phases of major project planning, execution, and delivery.
- Coordination of outages to ensure continuity of system performance during work execution.
- Adequate assessment of alternatives to proposed projects and programs.
- Continual reassessment and justification of business case at each phase of project planning and execution.
- Cost estimates that reflect reasonable assumptions and appropriate analysis of risk for setting project budgets.

[22] Code of Business Conduct and Business Ethics, ER-001.

- Growing and maintaining a competent, skilled management team of Hydro employees to provide appropriate oversight over contracted resources.
- Ensuring Management Reserve allocation appropriately reflects the complexity and strategic risks associated with the project.
- Engaging and informing the province regarding analyses, risks, changes, and decisions throughout all phases of major projects planning, execution, and delivery.
- Implementation of thorough and continuous risk management processes.
- Integration of major projects governance into existing corporate governance structures.
- Independent review and oversight of major projects.[23]

During the execution of each major project, a Lessons Learned Register will be developed to ensure future projects and programs can benefit from the experience gained on previous and current projects. As such, Hydro's approach to governance will be reassessed regularly and updated when prudent to ensure that new lessons learned are appropriately reflected.

5.4 Alignment with Existing Governance Structures

The Hydro Board of Directors (Board of Directors) and Executive Leadership Team oversee the approval and execution of major projects. Both the Board of Directors and Executive Leadership Team have members that have extensive utility experience, including experience with Hydro and the provincial electricity system. Further information regarding the integration of the major projects governance structure within Hydro's existing governance structure is provided in Section 8.0.

Additionally, the Internal Audit & Advisory Services Department, which is directly accountable to the Board of Directors' Audit Committee, has the ability to investigate, audit, and advise on major projects as they deem appropriate. Additional information regarding the role and responsibility of the Internal Audit & Advisory Services Department is provided in Sections 8.9 and 20.3.

6.0 Major Projects Department

To enable the necessary additional oversight requirements associated with major projects, Hydro has created a department dedicated to planning, executing, and delivering major projects (the Major Projects Department). The Major Projects Department is dedicated to and responsible for the planning, execution, monitoring, and delivery of major projects for Hydro. It is responsible for managing major projects and project resources in accordance with Good Utility Practice.

The Major Projects Department will be guided by a comprehensive framework of strategies, policies, and procedures that align with Hydro's overarching objectives and will incorporate industry practices. Critical processes are being implemented and followed and the finalization of documentation is being completed on a priority basis.

[23] The Public Utilities Board performs this function for regulated projects.

By centralizing the project management personnel and resources required for major projects into a single department, Hydro is able to achieve economies of scale and scope. Additionally, this approach permits Hydro to create and maintain consistent operational guidelines, plans, and standards to provide Hydro with the necessary skillsets, tools, oversight, and organizational expertise required for the success of major projects.

In establishing a dedicated Major Projects Department, Hydro is:

- Reinforcing the responsible planning, execution, and delivery of major projects as a corporate priority;
- Creating a structure that facilitates optimization of its existing resources and expertise while continuing to grow Hydro's qualified workforce;
- Providing clear and appropriate accountability for the successful delivery of major projects; and
- Facilitating consistent and transparent application of policies, procedures, practices, and oversight across major projects.

6.1 Major Projects Department Structure

The Major Projects Department is led by the Director of Major Projects & Asset Management. This position is directly accountable to the Vice President of Hydro Engineering & NLSO.[24] The Major Projects Department's Management Team has the appropriate skills, education, experience, and technical and professional competencies to provide appropriate support, management, and oversight of major project teams. The Major Projects Department also avails of support services from the broader Hydro organization, such as finance, information systems, operational technology, etc. The Manager of Corporate Interface role is responsible for liaising with such areas to ensure the needs of major projects are met and that Hydro is adequately prepared and resourced to provide the necessary support.

The Major Projects Department structure as of March 2025 is shown in Figure 3. The size and composition of the department are expected to fluctuate depending on the number, complexity, and phases of active major projects. The Major Projects Department's Management Team is shown in blue and their respective functional areas are shown in green.

[24] Newfoundland and Labrador System Operator (NLSO).

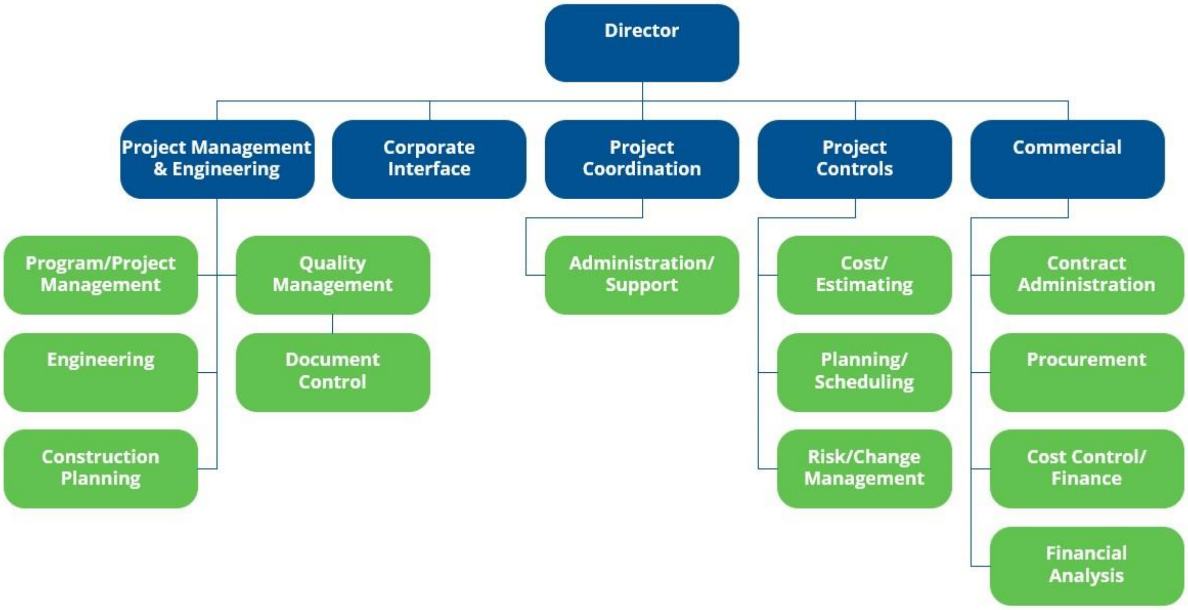

Figure 3: Major Projects Department Structure[25,26]

6.2 Major Projects Guiding Principles

To support the successful intake and execution of major projects in a manner that is aligned with Hydro's legislated mandate, values, and strategic goals, the Major Projects Department is guided by the following principles:

- **Promoting a Positive Safety Culture.** Ensuring a safe and healthy work environment is a top priority for all major projects.
- **Promoting Good Governance and Oversight.** Ensuring the governance model is effective and includes adequate monitoring and reporting to required stakeholders.
- **Timely and Evidence-Based Decision-Making.** Ensuring that decisions concerning major projects are made and documented in a timely fashion and based on reasonable and available evidence, with the view of delivering power at the lowest possible cost, consistent with reliable service in an environmentally responsible manner.
- **Strengthen Engagement Processes with Indigenous Peoples.** Working with Indigenous governments and community leadership to promote mutually respectful relationships and open, transparent sharing of information.
- **Strengthen Relationships with Interested Groups.** Ensuring transparency and accountability to interested groups, communities, and other partners of Hydro.

[25] Corporate Interface includes corporate business groups such as Safety, Environment, Information Systems, Information Management, Stakeholder Relations, Finance, etc.
[26] The long-term reporting structure for the Procurement function within the Major Projects Department remains to be determined.

- **Continuous Learning.** Reviewing and internalizing lessons learned from previous projects (including the Lower Churchill Project) and implementing learnings (positive and negative) into future planning and execution of major projects.
- **Building Competencies.** Building subject matter expertise within the Major Projects Department and the whole of Hydro.
- **Ensuring Organizational Readiness.** Preparing Hydro for the anticipated requirements of major projects execution.
- **Promoting Transparency.** Subject to security or confidentiality requirements, promoting transparency and accountability with respect to the initiation, planning, execution, and delivery of major projects.
- **Executing Projects in Accordance with Good Utility Practice.** Considering Good Utility Practice in the design and execution of major projects and project protocols at all times.
- **Evaluating and Managing Risks.** Throughout the individual major project(s) life cycle(s) and at an organizational level, identify, assess, rank and manage major project risks.
- **Supporting Sustainable Growth.** Supporting Hydro's commitment to contribute to sustainable prosperity within Newfoundland and Labrador.

7.0 New Governance Mechanisms

Hydro has established three new mechanisms to support major projects—the Major Projects Steering Committee (oversight), the Major Projects Risk Working Group (risk management), and the Major Projects Change Control Committee (change management). These groups each serve a specific function, as further described in this section. However, they all provide a mechanism to enable two-way communication from the Major Projects Department to the rest of Hydro about project and program activity that may affect Hydro's corporate activities and operations, and from the broader Hydro organization regarding corporate activities and operations that may affect projects, programs, and the Major Projects Department.

7.1 Major Projects Steering Committee

The Major Projects Steering Committee (Steering Committee) is comprised of Hydro's entire Executive Leadership Team, including the President and CEO. The Steering Committee provides a forum for obtaining executive-level approvals; providing updates related to current progress; identifying challenges; raising issues; and seeking input, guidance and advice on matters of high significance. The Major Projects Risk Working Group (Risk Working Group) and the Major Projects Change Control Committee (Change Control Committee) will report to the Steering Committee monthly. The Terms of Reference for the Steering Committee is provided as Attachment 1.

7.2 Major Projects Risk Working Group

The Risk Working Group is primarily comprised of members of the Major Projects Department's Management Team. The Risk Working Group provides a forum for comprehensive evaluation of risks. It also ensures effective management and communication of risks. This enables the Major Projects

Department and the Steering Committee to make risk-informed decisions, including the prioritization of major projects and resources.[27] The Terms of Reference for the Risk Working Group is provided as Attachment 2.

7.3 Major Projects Change Control Committee

The Change Control Committee is primarily comprised of members of the Major Projects Department's Management Team with additional representation from Hydro's corporate legal and finance teams. The Change Control Committee provides a forum for comprehensive evaluation of proposed project and program changes and ensures effective management and approval of such changes. The Change Control Committee enables the Major Projects Department and Steering Committee to make informed decisions, including appropriate allocation and communication of impacts and resources. The Terms of Reference for the Change Control Committee is provided as Attachment 3.

8.0 Governance Structure—Roles & Responsibilities

Figure 4 provides an overview of the governance structure for major projects.

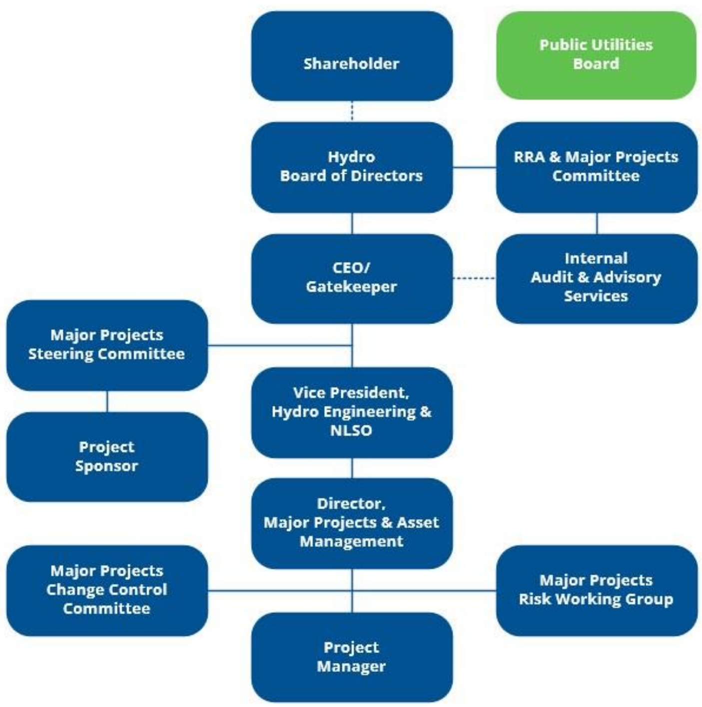

Figure 4: Major Projects Governance Structure

[27] An overview of the risk management process is provided in Section 12.0.

8.1 Project Manager

The Project Manager is accountable for project planning, execution, and completion activities on a day-to-day basis. The Project Manager is an individual with sufficient project management experience in similar projects to demonstrate competence and capability to fulfill the responsibilities of the role.

The primary responsibilities of the Project Manager are as follows:

- Ensure the development and implementation of project planning documents (e.g., project management, project execution plan, safety plan, etc.) in accordance with approved management frameworks;
- Ensure that project-level safety, quality, environmental, constructability, and maintainability programs are implemented and supported;
- Identify and manage project risks and implement and maintain the risk register;
- Identify stakeholders and implement and maintain the stakeholder register;
- Develop and implement the project communication plan;
- Ensure preparation of monthly update reports for the Project Sponsor and the Steering Committee;
- Identify, justify, approve, and manage project changes in accordance with the process and thresholds defined in the project change management plan and defined limits of authority;[28] and
- Successful delivery of the project in compliance with the approved project schedule, scope, and budget.

The Project Manager will have access to resources from the Major Projects Department as well as corporate departments to support them in carrying out their responsibilities. This includes but is not limited to project management, engineering, project controls, procurement/commercial support, safety, environment, stakeholder relations, corporate interfaces, and administration.

8.2 Major Projects Change Control Committee

The Change Control Committee oversees, evaluates, and approves changes affecting the project budget, scope, schedule, and quality in accordance with the authorization levels outlined in the Major Projects Change Management Plan.

The primary responsibilities of the Change Management Committee are as follows:

- Evaluate, approve, implement, and monitor trends and changes within a project (subject to the appropriate authorization levels outlined in the Major Projects Change Management Plan);
- Ensure changes that drive risk or are driven by risk mitigation strategies are appropriately communicated and coordinated with the Risk Working Group;

[28] As per Hydro's Signing Authorities Policy, FIN-012

- Ensure appropriate communication of changes and change management practices to Hydro's corporate interfaces, as required;
- Understand project and program changes and interdependencies and secondary impacts ("ripple effects") between projects and programs, including their impacts on ongoing operations and maintainability;
- Analyze and prioritize changes to provide a clear understanding of potential impact; and
- Promote corporate understanding of major projects changes and major projects understanding of the corporate impact of change.

8.3 Major Projects Risk Working Group

The Risk Working Group provides comprehensive oversight, identification, ranking, and management of the major projects' risks. The responsibilities of the Risk Working Group are as follows:

- Understanding major projects' risks and interdependencies between major projects;
- Proactively identify and rank risks, including corporate risks, that could impact Hydro's ability to deliver the goals and objectives of its major projects' portfolio;
- Analyze and prioritize risks, providing a clear understanding of potential impacts;
- Review tactical risks ranked as high and greater and approve appropriate risk management strategies for such risks;
- Review all escalated major project risks from a portfolio level to identify risk impacts between major projects, risk trends, emerging risks and risks that may impact Hydro corporately;
- Develop recommended risk management strategies for high and greater strategic risks and propose them to the Major Projects Steering Committee;
- Monitor and report on risk management strategies;
- Ensure alignment of major projects' risk processes and documentation with Hydro's corporate risk processes and documentation; and
- Promote corporate understanding of major projects' risks and major projects understanding of corporate risks through direct participation in Hydro's corporate ERM processes.

8.4 Director, Major Projects & Asset Management

The Director of Major Projects & Asset Management is responsible for providing senior management-level direction and oversight through all phases of major projects. The primary responsibilities of the Director of Major Projects & Asset Management (as it pertains to major projects) are as follows:

- Ensure production and updating of, and compliance with, this Governance Framework;
- Ensure appropriate resource planning for major projects (e.g., project estimating, workforce competencies, quantity, timing, etc.) in accordance with management strategies;
- Ensure proactive stakeholder management and support conflict resolution;

- Approve and ensure implementation of Major Projects Department-level documentation (e.g., management strategies) and major projects-specific planning documents;
- Ensure development of appropriate decision support packages to support major projects advancement through decision gates;
- Endorse major projects' advancement through decision gates;
- Monitor and approve the use of Contingency;
- Support reporting to the Reliability & Resource Adequacy and Major Projects Committee of the Board of Directors (RRA & Major Projects Committee), Board of Directors, Shareholder, Public Utilities Board, and other external stakeholders as required;
- Engage in conflict resolution (internal and external) as required; and
- Identify potential conflicts between corporate policies and major projects requirements, ensure such conflicts are brought to the attention of the Steering Committee, make recommendations and provide the necessary support to inform the Steering Committee's decision-making, and influence and support corporate policy changes, as appropriate.

8.5 Vice President, Hydro Engineering & NLSO

The Vice President of Hydro Engineering & NLSO is the executive accountable for oversight and direction provided through all phases of major projects. The primary responsibilities of the Vice President of Hydro Engineering & NLSO (as it pertains to major projects) are as follows:

- Endorse this Governance Framework for approval by the Board of Directors;
- Ensure project governance practices are in accordance with this Governance Framework;
- Ensure projects adhere to Hydro's corporate standards;
- Make decisions to advance major projects from concept design to feasibility design;
- Make decisions to advance major projects from feasibility design to FEED[29] up to $5 million;[30]
- Endorse projects' advancement through all remaining decision gates;
- Present human resource requirements to Hydro's hiring committee;
- Steward operating and project budgets for the Major Projects Department;
- Ensure appropriate reporting to the RRA & Major Projects Committee, Board of Directors, Shareholder, Public Utilities Board, and other external stakeholders as required; and
- Engage in conflict resolution (internal and external) as required.

[29] Front-End Engineering Design (FEED).
[30] Beyond the signing authority of the Vice President of Hydro Engineering & NLSO, the CEO will approve with the endorsement of the Vice President of Hydro Engineering & NLSO and the Vice President, Chief Financial Officer.

8.6 Project Sponsor

The Project Sponsor champions and supports the project at the executive level. They have sufficient influence to remove barriers to the major projects' success, generate resources for the project, and facilitate the resolution of potential conflicts.

Generally, the Project Sponsor for major projects is a member of the Executive Leadership Team with a substantial stake in the project based on their corporate accountabilities. In some cases, a non-executive senior leader with sufficient authority and influence to champion and support the project at the executive level may serve as a Project Sponsor.

Based on the recommendation of the Steering Committee, the CEO appoints the Project Sponsor. The primary responsibilities of the Project Sponsor are as follows:

- Approve the project charter and ensure alignment with Hydro's strategic goals;
- Ensure governance practices are in accordance with this Governance Framework;
- Ensure the project adheres to Hydro's corporate standards and achieves the business need;
- Monitor the use of Contingency and ensure appropriate change management process has been followed;
- Represent the major project at Steering Committee meetings; and
- Approve decision support packages to support the full approval and commitment to build decision gates.

8.7 Major Projects Steering Committee

The Steering Committee provides strategic oversight, guidance, and approvals for all major projects. The Steering Committee's visibility into all major projects ensures its decisions consider the aggregate impacts of the Major Projects Portfolio on Hydro's corporate resources and ensure overall alignment of the Major Projects Portfolio with Hydro's mandate and strategic goals.

The responsibilities of the Steering Committee include:

- Reviewing complexity assessments and determine whether projects are major projects;
- Ensuring the Major Projects Portfolio remains aligned with Hydro's mandate, vision, and strategic goals;
- Prioritizing projects within the Major Projects Portfolio;
- Ensuring major projects remain in alignment with business needs and strategic goals through all project phases;
- Approving project changes as outlined in the Major Projects Change Management Plan;

- Reviewing all risks ranked as high and greater and ensuring appropriate risk management strategies are in place for high and greater strategic risks;[31]
- Supporting stakeholder management; and
- Offering guidance and advice on specific items with high significance.

8.8 CEO/Gatekeeper

The CEO acts as the Gatekeeper for Hydro. Based on the outcome of FEED work, they make the recommendation to the Board of Directors to approve a major project and proceed to seek regulatory approval. Based on the outcome of detailed design and procurement, they make the recommendation to the Board of Directors to make the final commitment to build.

The primary responsibilities of the CEO/Gatekeeper (as it pertains to major projects) are as follows:

- Appoint a Project Sponsor;
- Support resourcing of major projects within the context of Hydro's organizational structure;
- Approve advancement through FEED stages where cost is expected to exceed $5 million;
- Review decision support packages to confirm alignment with corporate and project objectives, legal and regulatory compliance, and readiness to proceed;
- Endorse advancement through the early execution and full budget approval and commitment to build decision gates;
- Approve Authorizations for Expenditure;
- Approve the utilization of Management Reserve through the issuance of supplemental Authorizations for Expenditure;
- Accountable for ensuring regular project updates (including cost, schedule, scope, and risk) are provided to the Board of Directors and Shareholder through all project phases;
- Approval of contracts in accordance with the Signing Authorities Policy; and
- Engage in conflict resolution as required.

8.9 Internal Audit & Advisory Services

Hydro's Internal Audit & Advisory Services Department reports directly to the Audit Committee, which is a committee of the Board of Directors. This reporting structure enables it to provide independent and objective assurance and advice to ensure major projects are managed effectively, efficiently, and in alignment with Hydro's strategic goals and policies. The Internal Audit & Advisory Services Department has the ability to evaluate project controls, risk management, governance processes, performance, and compliance with applicable laws, regulations, and standards. The Internal Audit & Advisory Services

[31] Tactical risks ranked as low and medium and strategic risk ranked as low will be managed by the Project Manager. Tactical risks ranked as high and greater will be managed by the Risk Working Group and communicated to the Steering Committee for awareness. Strategic risks ranked as medium and greater will be communicated to the Steering Committee and the Steering Committee will approve risk management strategies for such risks.

Department will report audit results to the Major Projects Department, Steering Committee, and Audit Committee in accordance with the Internal Audit & Advisory Services Department's policies and procedures. Internal Audit & Advisory Services will also report all major projects-related audit results to the RRA & Major Projects Committee.

Hydro may elect to engage the Internal Audit & Advisory Services Department at various points through the major project's life cycle, or the Director of Internal Audit & Advisory Services may choose to undertake audits to test and ensure appropriate controls and conduct related to high-risk areas of major projects. Internal Audit & Advisory Services will attend meetings of the Steering Committee, Risk Working Group, and Change Control Committee for risk awareness.

8.10 RRA & Major Projects Committee of the Board of Directors

The Board of Directors has appointed the RRA & Major Projects Committee to review and consider any proposed major projects and applications to the Public Utilities Board related to major projects and report to the Board of Directors regarding its review. In accordance with its mandate, the RRA & Major Projects Committee is responsible for the following:

- Consider proposed major projects and related applications to the Public Utilities Board and report to the Board of Directors regarding such review;
- Ensure management has appropriate processes in place to estimate project cost and schedule and manage risk for major projects;
- Ensure management has an appropriate and effective governance framework in place to manage major projects;
- Monitor the progress of major projects and regularly report to the Board of Directors on key milestones, achievements, and challenges; and
- Other duties as may be necessary or appropriate under applicable law or as may be delegated to the RRA & Major Projects Committee by the Board of Directors from time to time.

8.11 Hydro Board of Directors

The Board of Directors is appointed by the Lieutenant-Governor in Council based on the recommendation of the Independent Appointments Commission of Newfoundland and Labrador. In terms of major projects, the Board of Directors is responsible for approving major projects' early execution, full budget [32] and final commitment to build, providing strategic oversight, and ensuring major projects' alignment with Hydro's corporate mandate and strategic goals.

The primary responsibilities of the Board of Directors (as it pertains to major projects) are as follows:

- Confirm major projects align with Hydro's mandate, vision, values, and strategic goals;
- Approve early execution and full budget for major projects and authorize applications to the Public Utilities Board for major projects;

[32] Subject to approval of the Public Utilities Board.

- Approve the final commitment to build;
- Monitor the progress of major projects and provide strategic oversight; and
- Other duties as may be necessary or appropriate under applicable law or as may be delegated to the Board of Directors by the Shareholder from time to time.

8.12 Public Utilities Board

As noted in Section 5.2.3, the Public Utilities Board is an external, independent regulatory body that is responsible for the general supervision of electric utilities, including Hydro. The Public Utilities Board has broad legislated power and responsibilities, as defined in the *Public Utilities Act*. Among other things, the Public Utilities Board has the authority to review, approve, and monitor Hydro's major projects unless they are otherwise legislatively exempt.

8.13 Government of Newfoundland and Labrador

The Government of Newfoundland and Labrador is Hydro's sole shareholder. Through the normal course of shareholder reporting and engagement, the shareholder is informed of major projects requirements, including scope and funding implications associated with the execution of major projects. Additional updates will be provided to the provincial government as required in anticipation of applications to the Public Utilities Board. Hydro keeps the provincial government informed throughout the duration of major projects; however, it is the Public Utilities Board that provides oversight.

9.0 Safety, Health, and Environment

All stages of major projects must comply with the overall requirements of Hydro's Safety and Health Management System, Occupational Health and Safety, and its Safety Credo. Hydro will also require contractors and subcontractors to implement and measure its own project-specific safety and health plan that must be at least as rigorous as that of Hydro. The Major Projects Health & Safety Management Strategy outlines the safety- and health-related requirements, roles and responsibilities, resources, and expectations of major projects, including contractor safety management. Hydro's Occupational Safety and Health Policy is provided as Figure 5.

Additionally, major projects must be compliant with Hydro's Environmental Management System Policy as well as any legislative requirements that apply to a specific major project. Hydro's Environmental Policy and Guiding Principles is provided as Figure 6.

Newfoundland and Labrador Hydro

Occupational Safety and Health Policy

At Newfoundland and Labrador Hydro (Hydro), we take pride in our commitment to ensuring employees, contractors and visitors go home safe and healthy each and every day. We are committed to preventing workplace injury and illness through active safety leadership, open reporting, and a focus on eliminating hazards and reducing risks to safety and health.

To succeed at our goal of an injury and illness-free workplace, our employees take personal responsibility to model positive safety behavior, and coach others to do the same. Leadership in safety and health is a continuous journey guided by our corporate values and safety excellence framework. It requires a supportive culture, effective procedures and equipment, as well as ongoing compliance at every level of the organization.

We are committed to maintaining and continually evolving our Occupational Health and Safety Management System that:

- encourages and supports the physical, psychological and social well-being;
- complies with the relevant legislative requirements and accepted industry standards and practices;
- documents safety and health objectives for achieving safety excellence and measures our performance against these objectives to ensure continual improvement; and
- engages our employees, Occupational Health and Safety Committees, and Workplace Health and Safety Representatives through meaningful consultation and cooperation in the development, maintenance and improvement of safety and health within the company.

No matter how busy we are, no matter the circumstance, no matter where we are – at Hydro, safety and health is always our first priority.

JENNIFER WILLIAMS
President and CEO, Newfoundland and Labrador Hydro

Date: August 2023

newfoundland labrador hydro

Figure 5: Occupational Safety and Health Policy

Newfoundland and Labrador Hydro

Environmental Policy and Guiding Principles

At Newfoundland and Labrador Hydro (Hydro) we are committed to being an Environmental Leader. We will help sustain a diverse and healthy environment for present and future Newfoundlanders and Labradorians by maintaining a high level of environmental compliance, responsibility and performance.

To succeed in our goal the following guiding principles have been established:

Awareness: We foster the environmental consciousness of employees and are committed to environmental compliance. We engage with identified interested parties, support stewardship in the community and participate in environmental research and development.

Environmental Management: We maintain an Environmental Management System to respond effectively to environmental emergencies and to manage, avoid or mitigate biophysical and socioeconomic effects for all of our activities and facilities.

Sustainability: We are committed to climate change management and adaptation and the efficient use of resources including the promotion of efficient use of electricity through internal and external programs. We apply a life cycle approach to planning and engineering, design, procurement and execution.

Leadership: We are committed to environmental stewardship through active leadership that promotes the identification of opportunities for continual improvement, establishes environmental targets and monitors and reports on environmental performance.

JENNIFER WILLIAMS
President and CEO, Newfoundland and Labrador Hydro

Revised: September 2023

newfoundland labrador hydro

Figure 6: Environmental Policy and Guiding Principles

10.0 Major Projects Phased Approval Process

Major projects will follow a phased approval process throughout the project life cycle. The phased approval process includes three work phases—Front-End Planning (FEP), Execution, and Close Out. While there may be instances where there is overlap between the various phases, they serve to identify the general sequence of project work, decision points, technical checkpoints, and internal and external reviews and approvals. Figure 7 illustrates the Major Projects Phased Approval Process, which provides for appropriate project justification and oversight throughout the entire project life cycle from initiation to close out, including early engagement of operations throughout the major project.

This structure will provide direction and guidance to the Major Projects Department, including:

- Mechanisms to enable best value-added potential to be captured and utilized;
- Mechanisms for the Steering Committee, Board of Directors, Public Utilities Board, and other stakeholders to verify the readiness to move from one phase to another in a systematic manner during the life cycle of a project;
- Demonstrating due diligence checks and balances are being applied during the execution of a major project; and
- Providing a means to pre-define "readiness" deliverables required for a major project to progress from one project phase to the next.

The Major Projects Department is developing an overarching Major Projects Project/Program Management Strategy for the initiating, planning, executing, controlling, and closing of major projects. It sets out the expectations for standards, plans, strategies, guiding principles, policies, and procedures for the Major Projects Department. Each major project will have its own detailed Project Execution Plan that will outline the specific approach and requirements for that specific major project.

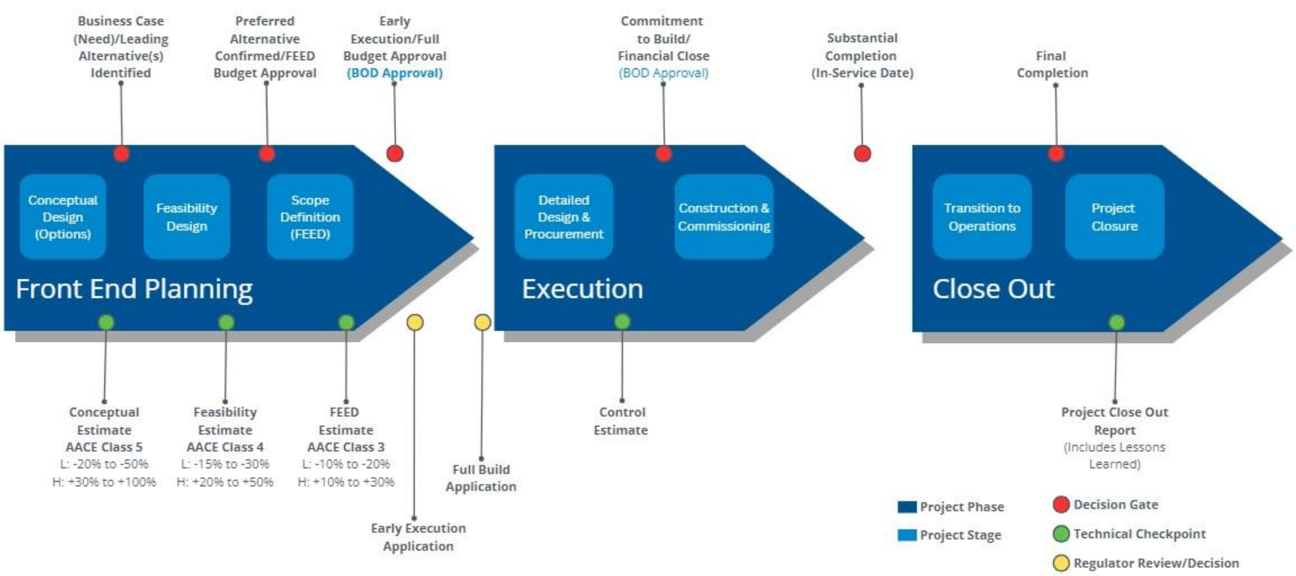

Figure 7: Hydro's Phased Approval Process for Major Projects

10.1 Major Project Phases and Stages

10.1.1 Phase One: Front-End Planning

The FEP phase lays the foundation for the successful execution of major projects by ensuring sufficient work is undertaken to clearly define the need, project strategy, scope, cost, and schedule to enable well-informed decision-making early in the project life cycle. FEP includes recognition of the need for a Major project, conceptual design and evaluation of alternatives, feasibility design for the preferred option, and FEED.

10.1.1.1 Conceptual Design

At the Conceptual Design stage, the need for the major project is confirmed and alternatives are identified. The need for a major project is typically identified through Hydro's RRA, Hydro's regular asset management program, or a customer request for power that is substantive enough to require investment in new generating, transmission, and/or distribution infrastructure. In cases where the need for a major project is identified through the RRA, the RRA process models the system needs and identifies the alternatives available to meet these needs.

10.1.1.2 Feasibility Design

At the Feasibility Design stage, the best viable alternatives are further assessed from a technical, operational, financial, environmental, safety, regulatory, and stakeholder perspective. Additionally, the cost estimates for each viable alternative are refined to an AACE Class 4 estimate. Feasibility Design provides a reasonable understanding of the scope, schedule, and cost estimate for each of the alternatives.

10.1.1.3 Front-End Engineering Design

FEED activities typically include scope refinement, preliminary engineering and design, refinement of cost estimates to an AACE Class 3 estimate, scheduling, risk assessment, stakeholder engagement, identification of permits and authorizations, delivery of a project-specific contracting strategy, establishment of quality standards, etc. Detailed FEP—including the development of the path of construction and identification of critical path activities, such as long lead equipment)—during this stage of a major project leads to improved accuracy of project estimates and schedules. In consultation with other parts of Hydro's business (e.g., Operations, Resource and Production Planning, etc.) the Major Projects Department works with FEED consultants to review assumptions, analyses, and recommendations to ensure ongoing operability and maintainability requirements are appropriately captured.

10.1.2 Phase Two: Execution

The next phase of a major project is the Execution phase. This phase includes detailed design and procurement and construction and commissioning. During this phase, the Major Projects Department works with other parts of the Business (e.g., Operations, Resource and Production Planning, etc.) to ensure design bases are set and that any potential changes are managed with operations and maintainability considerations taken into account.

10.1.2.1 Detailed Design & Procurement

In the Detailed Design & Procurement stage, the engineering concepts developed during the FEED stage are refined and precise technical drawings and specifications are produced. At this stage, engineering designs are finalized, material and equipment specifications are defined, construction drawings are developed, system integration plans are developed, quality assurance standards are established, and safety and environmental compliance measures are implemented.

Procurement activities ramp up significantly in the detailed design and procurement phase. Procurement planning informed by design requirements advance, including identification of procurement needs and procurement scheduling. Vendor prequalification, tendering and bidding, and contract negotiations and awards also occur in this phase.

10.1.2.2 Construction & Commissioning

The second stage of the Execution phase is the Construction & Commissioning stage of the major project. It is at this stage that the project is physically realized and the asset(s) are built, tested, commissioned, and made operational.

The Project Manager provides day-to-day oversight and supports changes to scope, budget, and/or timelines in accordance with the Major Projects Change Management Plan. The Project Manager reports progress and escalates issues in accordance with the governance structure established in Section 8.0. The Steering Committee monitors progress, supports resolution of issues that require executive and Board of Directors-level engagement, and ensures stakeholder alignment.

During the Construction & Commissioning stage, site oversight is critical. The Project Manager will ensure regular communications between the site and the Major Projects Department's Management Team. A Construction Management Team will maintain a consistent presence at the site to provide field oversight. The Major Projects Department's Management Team provides regular progress updates to the Steering Committee, RRA & Major Projects Committee, CEO, and Board of Directors. The content and frequency of these updates will depend on the nature of the project and will take into account project complexity, stakeholder needs, risks, safety and health exposure, and project performance (e.g., cost overruns, schedule delays, scope creep, etc.).

Although operational requirements are considered throughout the project life cycle, it is during this stage readiness for operations deliverables are transitioned from the project contractors to the major project team and critical handover completion documentation is finalized and accepted by the major project team.

10.1.3 Phase Three: Close Out

The Close Out phase includes the transition of the major project's assets to operations and project closure.

10.1.3.1 Transition to Operations

Although operations would have been engaged during the earlier stages of the project, it is during the Transition to Operations stage that readiness for operations deliverables are transitioned from the major project team to operations and critical turnover completion documentation is finalized and accepted by operations.

Activities in this stage include planning for operational readiness, system integration and handover, documentation and knowledge transfer, close out of construction and commissioning, performance monitoring, and risk and compliance management. It also includes the transition of risk ownership from the major projects' team to the operational area that will operate and maintain the asset, ensure safety, regulatory, and environmental requirements during operations are understood and met, and obtain acceptance of the asset from the operational area that will operate and maintain the asset.

10.1.3.2 Project Closure

The final stage of a major project is completing project closure activities. Project closure activities include decommissioning and removal of construction-related equipment and facilities that will not be required for operations. It also includes confirming the completion of deliverables, documenting handover, financial closure, administrative closure, knowledge transfer and training, archiving lessons learned, and completing the project close out report.

10.2 Decision Gates

10.2.1 Identify Business Case/Leading Alternatives

At the conclusion of the Conceptual Design stage, a concise, business case is prepared.[33] The document includes a summary of the business need, a brief description of the alternatives, the AACE Class 5 estimate for each technically feasible alternative, and the potential implications of deferring the major project.

Approval of the Vice President of Hydro Engineering & NLSO is required to proceed to the next stage, Feasibility Design.

10.2.2 Confirm Preferred Alternative & FEED Budget Approval

At the conclusion of the Feasibility Design stage, FEED alignment documentation will be prepared. This documentation includes similar information to the previous stage—a summary of the business need, a brief description of the preferred alternative(s) to be studied,[34] and the AACE Class 4 estimate(s) for the preferred alternative(s), schedule, and other relevant considerations (e.g., safety, environmental, etc.).

If the FEED cost estimate is $5 million or less, approval of the Vice President, Hydro Engineering & NLSO is required to proceed to FEED. If the FEED cost estimate is greater than $5 million, the CEO (with endorsement of the Vice President of Hydro Engineering & NLSO and the Vice President, Chief Financial Officer) will provide approval to progress to FEED.

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[33] In cases where the need for a Major Project is identified through the RRA, the RRA process models and documents the system needs and identifies the alternatives available to meet the system need.
[34] The preferred alternative(s) must be justified in the context of Hydro's legislated mandate to provide power at the lowest possible cost consistent with reliable service in an environmentally responsible manner.

10.2.3 Early Execution

If the timeline for obtaining regulatory approval of the major project is anticipated to exceed the timeframe for advancing critical path work required to maintain the project schedule, Hydro will also seek approval to proceed with Early Execution. The scope of Early Execution will be limited to the work that is necessary prior to receiving regulatory approval for the project.

Similar to the Full Budget decision, the Steering Committee and the CEO endorse the Early Execution for approval by the Board of Directors. The Board of Directors authorizes the Early Execution of capital work (including the associated budget) and authorizes Hydro to make an application to the Public Utilities Board for regulatory approval of the Early Execution of capital work.

Once regulatory approval is obtained, the CEO will issue an Early Execution Authorization for Expenditure denoting the portion of the approved budget, net of any Management Reserves, that is released to the Major Projects Department for execution.

10.2.4 Full Budget Approval

The conclusion of FEED efforts marks the end of the Front-End Planning phase. Prior to proceeding to the Execution phase, the Steering Committee and the CEO endorse the major project for approval by the Board of Directors. The Board of Directors will approve the major project and authorize Hydro to make an application to the Public Utilities Board for regulatory approval of the major project.

The documentation required to support this decision is referred to as the Decision Support Package. The Decision Support Package is prepared by the major project team and includes the appropriate level of justification, rationale, and documentation to support the assessment of a full budget decision.

Generally, a Decision Support Package will include an overview of the following:

- Business case justifying the need for the major project and alignment with Hydro's strategic goals, a summary of the alternatives considered, and a cost-benefit analysis;
- Overview of the project scope, technical feasibility, and supporting design documentation;
- AACE Class 3 cost estimate (in alignment with AACE maturity matrix) and details supporting proposed Contingency and Management Reserve;
- Justification for budget (based on results of Monte Carlo simulation);[35]
- Overview of financing plan or options (if known at the time);
- Overview of stakeholder engagement;
- Project schedule;
- Overview of regulatory and environmental requirements and how the proposed project will meet them;

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[35] Generally, major projects will seek budget approval based on a P85 estimate but may be higher or lower depending on project complexity, risk, and uncertainty.

- Overview of team's technical competence and capability to execute;
- Overview of high risks and risk management strategies;
- Overview of project management and project execution plans;
- Assessment of lessons learned from previous projects, audits, regulatory proceedings, etc.; and
- Overview of third-party reviews or engagements, as applicable.

The particular documentation and analyses required for a Major Project's Decision Support Package will be driven by the particulars of the major project seeking Full Budget approval. The major projects team will consider the project's complexity assessment, stakeholders, risks, and governance requirements when preparing the Decision Support Package.

Once regulatory approval is obtained, the CEO will issue an Authorization for Expenditure denoting the portion of the approved budget, net of any Management Reserves, that is released to the Major Projects Department for execution.

10.2.5 Commitment to Build

At the end of the Detailed Design & Procurement stage, project costs will be re-forecasted and an updated project schedule will be available. If the re-forecasted cost or schedule is materially different from what was originally approved by the Board of Directors, additional work will be completed to understand the drivers of the change and further refine the budget and schedule.

The major project team will reassess and reaffirm the decision to proceed with the project and seek approval from the Board of Directors to proceed with the project based on the updated information. This gives the Steering Committee, CEO, and Board of Directors the ability to make a decision that is informed by a more current and accurate forecast of the cost, an updated risk assessment, and an understanding of the project activities completed to date and those remaining.

This is a significant milestone in the project as it confirms project readiness, validates the financial viability of the project, ensures appropriate risk management is in place, and is a mechanism to reaffirm alignment with key stakeholders. To ensure continuity of project momentum, this decision must be made in a timely manner at a specific point in time for the project. Essentially, it must be made before the "point of no return" (i.e., the point where stopping the project becomes more costly than continuing to completion). If the decision is not made in a timely manner, it presents the risk of procurement timelines lapsing, project delays, cost increases, etc. For this reason, the timing of this decision may vary from project to project depending on the particulars of that project.

The major project team prepares the documentation required to inform the Commitment to Build. Similar to the Decision Support Package, the specific documentation required for the Commitment to Build may vary depending on the particulars of a project, including the degree to which the updated project cost and schedule differs from that which was previously approved.

Generally, the documentation required to inform the Commitment to Build decision includes an overview of the following:

- Updated budget forecast to completion;
- Updated project schedule;
- Explanation of timing of decision point (i.e., why this point in time is critical and is essentially the “point of no return” on a project);
- Overview of procurement activities to date, including procured equipment and materials and delivery schedules; and
- Current risk assessment.

Similar to the Full Budget decision, the Steering Committee and CEO will endorse the Commitment to Build for approval by the Board of Directors. The Board of Directors will approve the Commitment to Build and Hydro will communicate the Commitment to Build decision to the Public Utilities Board.[36]

10.2.6 Substantial Completion

The NLSO and Operations must make the decision on acceptance of the major project as substantially complete and authorize its in-service date. To inform this decision gate, the major project team will prepare a Turnover Package. The content of the Turnover Package will vary based on the particulars of a project; however, the Turnover Package will generally include:

- Project overview, including key milestones and benefits achieved;
- Criteria that define substantial completion of the project and confirmation that those criteria have been met;
- Punch list items;
- Detailed design documentation, as-built information, and operation manuals;
- Warranties and guarantees;
- Assessment of operational readiness for project in-service;
- Documentation to demonstrate safety and environmental, regulatory, and contractual compliance;
- Results from commissioning tests, including comparison of test performance to design plan (e.g., operating manuals, warranty info, etc.);
- Risk analysis;
- Proposed in-service date; and
- Approvals and endorsements from key stakeholders.

[36] The Public Utilities Board’s Capital Budget Guidelines require Hydro to report to the Public Utilities Board for further review if costs to completion are forecasted to exceed 10% of the approved project budget; however, the Public Utilities Board has the ability to modify this threshold at its discretion. Hydro will comply with the threshold required by the Public Utilities Board.

10.2.7 Final Completion

At the end of the Transition to Operations stage, the Vice President responsible for operations must decide to accept the major project as complete. To inform this decision gate, the major project team will prepare a project close out package to provide the necessary information to confirm that the project has met its objectives, contractual obligations, and safety, environmental, and regulatory compliance requirements. It also validates that the assets are operational and functioning in alignment with the approved project specifications and that all documentation required for operating and maintaining the asset has been provided.

The content of the project close out package will vary based on the particulars of the project; however, the project close out package will generally include:

- Criteria that define final completion of the project and confirmation that those criteria have been met (e.g., final scope review, as-built documentation, outstanding punch list items, etc.);
- Assessment of performance and commissioning and testing reports;
- Updated punch list;
- Commitment register; and
- Confirmation from legal and compliance teams that all contractual, legal, and regulatory obligations have been met.

In addition to the project close out package, the major project team will prepare a project close out report that will be retained by the Major Projects Department. The report will include:

- Project overview, including key milestones, success metrics, and benefits achieved;
- Financial summary, including final costs compared to budget and a forecast of remaining costs to completion;
- Approvals and endorsements from key stakeholders;
- Contract close-out documentation; and
- Results of any independent assessments undertaken or independent opinions sought to confirm project finalization.

11.0 Project Budget & Financial Authorization

11.1 Authorizations for Expenditure

Major projects require approval of the Board of Directors prior to proceeding with the project or proceeding with an application to the Public Utilities Board for regulatory approval to proceed with the project, as described in Section 10.2.4. Once project budgets are approved by the Board of Directors, an Authorization for Expenditure form is the mechanism that establishes the budget, allowing the budget to be applied to the project components and drawn down as the project progresses. The purpose of this process is to provide the CEO with the ability to control the amount of budget available to the major projects team for execution, net of any Management Reserves.

If a project requires Early Execution, as described in Section 10.2.3, the Board of Directors and Public Utilities Board will approve the Early Execution of capital works. On that basis, the CEO will sign an Authorization for Expenditure form for the approved budget, net of any Management Reserves. This amount will be made available for use by the major projects team to execute the approved scope of Early Execution necessary to maintain cost and schedule.

Once the project receives approval from the Public Utilities Board, the remainder of the planned project budget (i.e., the total authorized budget less the amount already allocated for Early Execution), net of any Management Reserves will be added to a Supplemental Authorization for Expenditure form. The CEO will sign the form, authorizing the release of the planned project budget to the major projects' management team.

Costs are monitored and reported on throughout the project, as described in Section 14.3. Any use of Contingency or Management Reserve will be processed and approved in accordance with the change management process as outlined in the Major Projects Change Management Plan. If costs are forecast to exceed the approved project budget (i.e., both the planned project budget and Management Reserve), Hydro will inform the Board of Directors. Additionally, in accordance with the Capital Budget Guidelines,[37] the major projects team must report to the Public Utilities Board for further review if costs to completion are forecasted to exceed 10% of the approved project budget, or some other threshold as determined by the Public Utilities Board.[38]

11.2 Utilization of Approved Project Budgets

Once the CEO has approved an Authorization for Expenditure, the project budget including Contingency (i.e., the planned project budget) is released for use by the major projects team. The Project Manager has the authority to manage within the approved baseline project budget. Use of Contingency requires prior approval of the Director of Major Projects & Asset Management.

Use of any amount of the Management Reserve requires justification and prior approval of the CEO. Release of Management Reserve funds requires those funds to be added to the Authorization for Expenditure form and signed by the CEO.

The authority for each component of the Authorized Budget is shown in Figure 8.

[37] "Capital Budget Application Guidelines (Provisional)," Board of Commissioners of Public Utilities, January 2022, sec. 6, p.5, states, "A change will be considered material if the nature or scope of the project changes such that that original rationale provided is no longer applicable or where the revised forecast expenditure exceeds the approved amount by 10% or more." <http://pub.nl.ca/PU/guidelines/Capital%20Budget%20Application%20Guidelines%20(Provisional)%20-%202021-12-20.PDF>

[38] Depending on the stage of a major project, Hydro may not be able to pause the project during the Public Utilities Board's review without incurring significant costs.

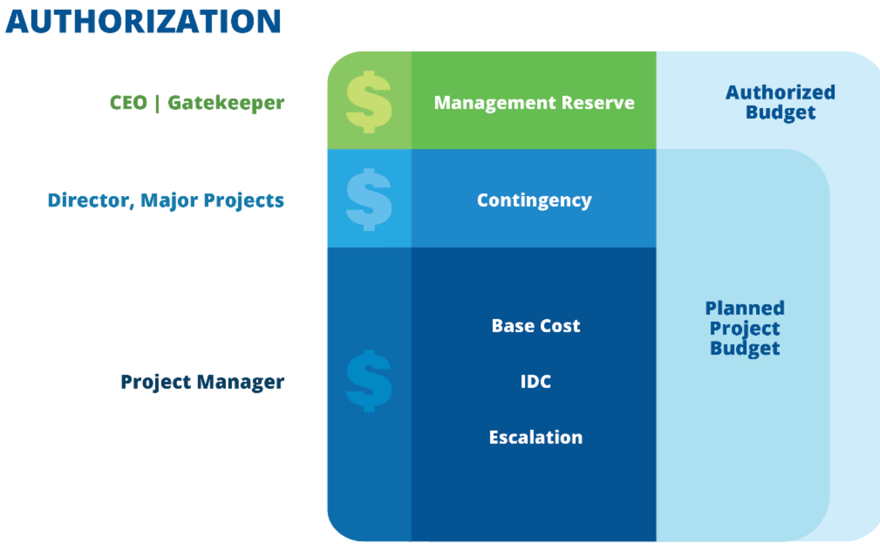

Figure 8: Project Budget Summary

Contingency is the amount of money allocated in the schedule or cost baseline for known risks with active response strategies.[39] This amount is added to an estimate to allow for items, conditions, and events for which the outcome is uncertain and that experience shows will likely result in additional cost. Contingency includes things such as planning and estimating changes, minor price fluctuations, design developments and changes within the scope, variations in market and environmental conditions, etc. Contingency typically does not include things such as:

- Major scope changes, such as changes in end product specification, capacities, building sizes, and location of the asset or project;
- Extraordinary events, such as major strikes and natural disasters;
- Management Reserves; and
- Escalation and currency effects.[40]

Due to the tactical nature of matters that require the use of Contingency, it is appropriate for the Director of Major Projects & Asset Management to have the authority to use it on major projects. They have the appropriate seniority and project-level knowledge to make timely decisions and be held accountable for the outcome of such decisions.

Management Reserve is an amount that is held outside of the performance measurement baseline for management control purposes and is reserved for unforeseen work that is within the project scope.[41] Essentially, it is reserved for the management of strategic risks that materialize that are outside of

[39] *PMBOK Guide: A Guide to the Project Management Body of Knowledge*, seventh edition, Project Management Institute, p. 237.
[40] Escalation and currency effects are included in the Planned Project Budget.
[41] *PMBOK Guide: A Guide to the Project Management Body of Knowledge*, seventh edition, Project Management Institute, p. 242.

Hydro's control. Management Reserves are useful in reducing risks when the major projects team finds possible risks that can potentially affect the project's schedule, scope, or budget. It can be used to cover items such as resource shortages, technological difficulties, governmental policy changes, economic volatility (e.g., tariffs), supplier delays, etc. The Management Reserve equips the project execution team to respond to strategic risks or unforeseen events quickly. Major projects can keep moving forward and remain on schedule despite obstacles outside of Hydro's control. A well-managed Management Reserve is a crucial tool since it increases the likelihood that the major project will succeed.

The inclusion of a Management Reserve in the project budget is also a finding of the Muskrat Falls Inquiry. Commissioner Leblanc noted that "A reasonable reserve for strategic risk should have been included in the Project's cost estimate and made known to GNL."[42]

Due to the strategic nature of matters that require the use of the Management Reserve, it is appropriate that CEO approval is required to access it. Strategic risks that increase or materialize should be escalated through the risk management process and the Steering Committee and CEO should have an understanding of the rationale for using the Management Reserve and the risk management strategies that are being used to address it.

It is industry standard to include both contingency reserve and Management Reserve in project estimates.[43] For each major project, Hydro will assess the Contingency and Management Reserve requirements in consideration of the project-specific risks, lessons learned, and best practices.

Financial authorizations for the award of contracts and procurement are in accordance with Hydro's Signing Authorities policy.

12.0 Risk Management

Risk management is the process of identifying, analyzing, evaluating, developing and implementing management strategies, assigning accountability, and monitoring risks. This process is illustrated in Figure 9.

[42] "Muskrat Falls: A Misguided Project, Commission of Inquiry Respecting the Muskrat Falls Project," The Honourable Richard D. LeBlanc, Commissioner, March 5, 2020, vol. I Key Finding 41, p. 53.
[43] For example, BC Hydro and Manitoba follow this practice. It is also recommended by AACE.

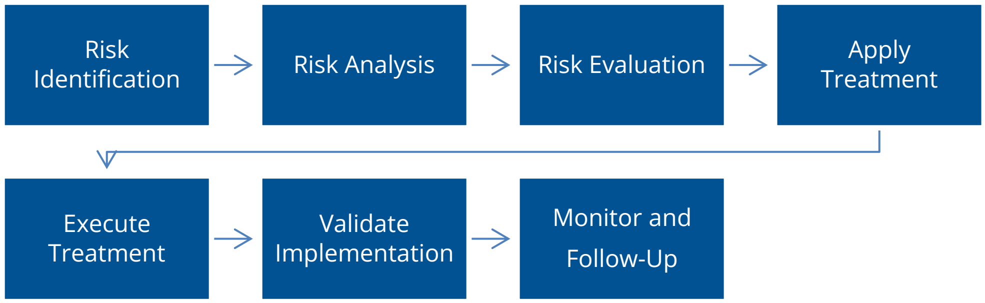

Figure 9: Risk Management Process

According to the Project Management Institute's Risk Management in Portfolios, Programs, and Projects, risk management allows organizations to:

- Anticipate and manage change;
- Cultivate a culture that balances risk, creativity, innovation, safety, and thoughtfulness;
- Be more agile and adaptable while supporting organizational resilience;
- Improve decision-making processes;
- Proactively implement potentially lower cost/time preventative actions instead of higher-cost/time corrective actions to issues;
- Engage stakeholders effectively;
- Increase the chances to realize opportunities for the benefit of the organization;
- Integrate sustainable, continuous improvement throughout the major projects' life cycle;
- Promote awareness of uncertainties and associated impacts; and
- Act upon the transformations taking place in the organizational environment.[44]

Effective risk management is critical to the success of major projects. It allows Hydro to proactively identify risks that could affect program or project objectives which, in turn, increases the predictability of project outcomes, helps manage complexity, helps maintain project cost, schedule, and budget, supports change management, and generally supports the delivery of the intended strategic business objectives associated with the major project.

As major projects introduce significant risks and opportunities to many areas of Hydro's organization, it is important that project risk management integrates with Hydro's existing corporate ERM. The overlap between major projects risk and corporate risk is shown in Figure 10.

[44] *Risk Management in Portfolios, Programs, and Projects: A Practice Guide*, Project Management Institute, 2024, p. 1.

Figure 10: Interaction between Enterprise Risk Management and Project Risk Management

To achieve the necessary integration of major projects and corporate risk, major projects will have risk management at the project, portfolio, organizational, and corporate oversight levels. This hierarchy of risk management and its integration with Hydro's corporate ERM is further explained in the sections that follow.

12.1 Major Project Risk Management

There are two levels of risk that must be managed on major projects:

1. **Tactical Risks:** The risk amounts associated with the base capital cost estimate and that result from uncertainties within the four components of that estimate: (a) project definition and scope omission; (b) construction methodology and schedule; (c) performance factors; and (d) price;[45] and

2. **Strategic Risks:** The identified background risks that are outside the control of the major project team.[46]

Each of these risks requires a different approach to management and escalation. To ensure appropriate management and oversight, major projects risks are managed at the project, portfolio, organizational, and corporate oversight levels and directly integrated into Hydro's existing corporate ERM.

[45] "Muskrat Falls: A Misguided Project, Commission of Inquiry Respecting the Muskrat Falls Project," The Honourable Richard D. LeBlanc, Commissioner, March 5, 2020, vol. I, p. 81.
[46] "Muskrat Falls: A Misguided Project, Commission of Inquiry Respecting the Muskrat Falls Project," The Honourable Richard D. LeBlanc, Commissioner, March 5, 2020, vol. I, p. 80.

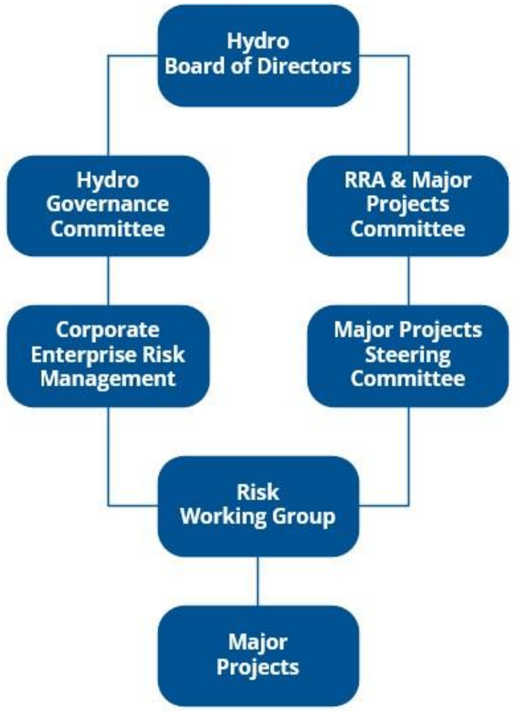

Figure 11: Risk Management Hierarchy

Hydro's approach to governance of risk management at each level is detailed in the sections that follow. Further detail on Hydro's overall approach to major projects risk management is provided in the Major Projects Risk Management Framework.

12.1.1 Major Projects Level

At the major projects level, the Project Manager is responsible for developing and maintaining project risk registers that identify, rank, manage, and assign accountability for strategic and tactical project risks. The Project Manager is the individual with the best knowledge of all aspects of the project and is, therefore, best suited to be the person with primary accountability to identify, assess and reassess, prepare strategies, carry out risk management activities, inform reporting, and close out risks. However, all members of the major project team have a responsibility to identify risks and communicate them to the Project Manager.

The Director of Major Projects & Asset Management ensures that the Project Manager assigned to a given major project has the necessary skills, education, experience, and overall competence and tools to ensure they are capable of executing the role of the Project Manager, including risk management. The Project Manager has the authority to manage tactical risks that are ranked low and medium and strategic risks that are ranked low, communicating and escalating any changes in risk ranking as required. The Project Manager is also responsible for ensuring that any risk management strategies that result in change follow the appropriate change management processes in accordance with the Major Projects Change Management Plan.

The Project Manager escalates tactical and strategic risks that are ranked high and greater, including recommended risk management strategies, to the Risk Working Group.

12.1.2 Major Projects Portfolio Level

As the Risk Working Group is comprised primarily of the Major Projects Department's Management Team, portfolio-level risks and escalated project risks are managed through the Risk Working Group. The Risk Working Group comprehensively identifies, assesses, and documents risks across all projects and programs, taking into consideration interdependencies between projects, programs, and corporate initiatives and risks.

The Risk Working Group approves risk management strategies for tactical risks ranked as high and greater and communicates them to the Steering Committee for awareness. For tactical risks that are ranked high and greater post-treatment and strategic risks ranked as high and greater, the Risk Working Group proposes risk management strategies for approval by the Steering Committee. The Risk Working Group oversees implementation and ensures the effectiveness of risk management strategies. The Risk Working Group Terms of Reference, provided in Attachment 2, further outline the responsibilities and expectations of the Risk Working Group.

12.1.3 Organizational Level

The Steering Committee is comprised of Hydro's Executive Leadership Team. This provides a fulsome organizational view to risk management. The Steering Committee is responsible for approving proposed risk mitigation strategies for strategic risks ranked as high and greater, and for ensuring that a structure to facilitate the identification of corporate initiatives or requirements that may introduce or affect risk for major projects and appropriate risk management strategies are implemented by the major projects team. Similarly, the Steering Committee members are expected to communicate their knowledge of any major projects' risks that could introduce or affect risk for their operational areas of accountability.

From a risk perspective, the Steering Committee also participates in the identification of risks for escalation to the Board of Directors as required.

12.1.4 Corporate Oversight Level

The Board of Directors has established a committee of the Board to provide focused oversight for the RRA and Major Projects (RRA & Major Projects Committee). The RRA & Major Projects Committee is comprised of Directors who have extensive utility experience and knowledge of the provincial electrical system, making them well-suited to overseeing risk management for major projects.

The RRA & Major Projects Committee will receive regular updates overviewing high and greater risks, as well as any implemented risk management strategies. Their role is not to approve risk management strategies; it is to ensure that appropriate risk management programs are in place and that they are effectively managing risks in a way that supports project success and alignment with Hydro's mandate, vision, values, and strategic goals. The RRA & Major Projects Committee may also bring forward any emerging risks that they are aware of for the major project team and Steering Committee to evaluate, assess, manage, and report back.

The RRA & Major Projects Committee reports directly to the Board of Directors.

12.2 Alignment with Hydro's Corporate ERM

To support alignment between major projects and Hydro's corporate mandate and strategic goals, risk practices for major projects will align with Hydro's corporate ERM approach.[47] Hydro's risk management process is a continuous process whereby risks are identified, analyzed, evaluated, treated, and monitored on an ongoing basis. Operationally, this process is achieved through the semi-annual meetings of working groups, management risk committees, a Strategic Risk Committee, and the Governance Committee.[48]

- **Working Groups.** Hydro has ten risk working groups representing all areas of the business, one of which is the Major Projects Risk Working Group. The Corporate Risk team facilitates meetings with each group to review risks for their respective areas and identify any emerging risks. These groups are responsible for risk identification and initial analysis. The Major Projects Risk Working Group is responsible for ensuring major projects' risks are appropriately identified and managed through the corporate ERM process.
- **Management Risk Committees.** The chair of each risk working group represents that risk working group at one of two management risk committees[49] that also meet on a semi-annual basis. These committees review the feedback from the risk working groups and further assess and evaluate risks. Where ownership and actions/treatments of risks are straightforward, this group also recommends them.

  Due to the magnitude of risks and opportunities that major projects present to a number of areas within the broader Hydro organization, the Major Projects Risk Working Group will have a representative participate in both management risk committees. The purpose of having major projects represented on both management risk committees is to ensure that major projects' risks are communicated to all areas of the business and that potential direct and indirect impacts of such risks on Hydro's corporate activities can be managed appropriately. Participation in both management risk committees also provides an opportunity for corporate risks to be best communicated and understood by the Major Projects Department.
- **Strategic Risk Committee.** The Corporate Risk team uses the feedback collected and produced by the risk working groups and the management risk committees to draft Hydro's Top Risk Report. This report is presented in draft to the Strategic Risk Committee on a semi-annual basis. The Strategic Risk Committee is comprised of the Hydro Executive Leadership Team. The Strategic Risk Committee reviews the top risks, identifies any areas requiring executive actions/treatments, and assigns ownership of those actions/treatments. The Strategic Risk

[47] ERM is not a function or department; rather, it is the culture, capabilities, and practices that organizations integrate with strategy setting and apply when they carry out that strategy, with the purpose of managing risk in creating, preserving, and realizing value.
[48] The Governance Committee is a committee of the Board of Directors that is responsible for overseeing Hydro's development of governance principles; regulatory activities and compliance processes; ERM; and sustainability policy, strategy, and reporting.
[49] The two management risk committees are the Operational Risk Committee and the Financial, Regulatory, and Compliance Committee.

Committee also reviews, approves, and obtains alignment on what will be presented to the Governance Committee of the Board in the Hydro Top Risk Report.

The Vice President accountable for the Major Projects Department is a member of the Strategic Risk Committee and represents major projects in that forum.

- **Governance Committee**: Following the alignment of the Strategic Risk Committee, the Corporate Risk team finalizes the Top Risk Report and presents the findings to the Governance Committee. Hydro's Top Risk Report will include major projects-related risks that are meet the threshold of being top risks.

The existence of a Major Projects Risk Working Group and having major projects representation on both management risk committees ensures that risks associated with major projects are known and understood by the corporation, as well as ensuring that corporate risks are known and understood by major projects.

13.0 Stakeholder Engagement

Stakeholders will vary from project to project depending on the nature of a particular major project. Generally, stakeholders will include:

- Internal stakeholders, such as the Major Projects Department, other impacted Hydro departments, executive team members, employees, etc.;
- External stakeholders, such as customers, taxpayers, union leadership, suppliers, consultants, not-for-profit groups, etc.;
- Regulatory bodies, including the Public Utilities Board, Department of Environment and Climate Change, Workplace NL, etc.;
- Indigenous communities, organizations, and groups;
- Local municipalities and community groups; and
- Hydro's shareholder (the provincial government).

The Major Projects Department is committed to understanding and appropriately managing the needs of its stakeholders, including understanding and complying with its legislative obligations associated with stakeholder consultation and engagement.

To facilitate this, all major projects will have a Stakeholder Matrix that outlines all the major project's stakeholders and their specific needs as it pertains to the project. Each major project will also have a stakeholder plan that will outline the various stakeholder engagement requirements and plans to address stakeholder needs. Both of these documents also inform the major project teams' understanding and management of stakeholder risks and prioritization of resources in terms of stakeholder management.

14.0 Project Controls

The Major Projects Department has a Project Controls Team that reports directly to the Director of Major Projects & Asset Management. This team is responsible for estimating, planning and scheduling, cost control, progress and performance management, risk management, change management, and reporting for all Major Projects under the accountability of the Major Projects Department.

Project controls enable effective governance oversight. It provides for consistency and standardization of data collection and reporting, early identification and management of deviations in scope, budget, and schedule, and enables informed decision-making throughout projects. The various project control functions are further outlined in the Major Project Projects Controls Strategy.

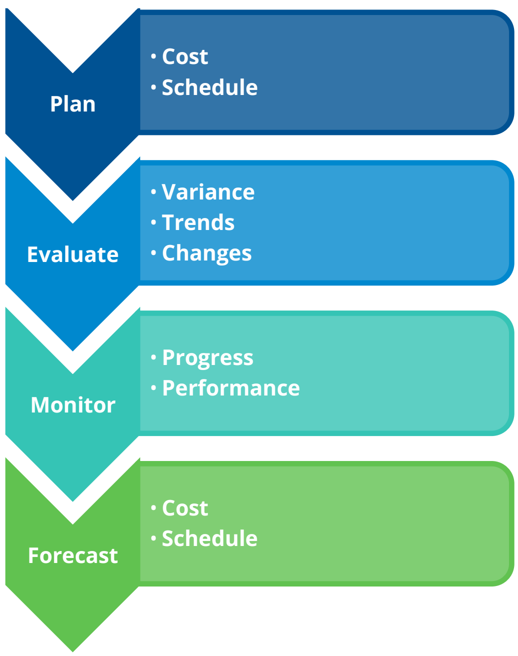

Figure 12: Project Controls Process

14.1 Cost Estimating

The Planned Project Budgets for major projects are the sum of the Project Capital Cost Estimate, Interest during Construction, and Escalation.

The **Project Capital Cost Estimate** includes the following:

- **Base Cost**, which includes prices for direct costs, such as equipment, materials, etc., and indirect costs, such as access roads, engineering, and temporary camps;
- **Design Allowance**, which accounts for natural changes and refinement of the scope of work as engineering progresses; and

- **Contingency**, which accounts for uncertainties outside of the major project's management team's control. They are the "known unknowns" that are within the project scope (e.g., geotechnical conditions).

The sum of these costs makes up the Project Capital Cost Estimate.

To establish the **Planned Project Budget**, the following is also included:

- **Interest during Construction**, which accounts for the cost of borrowing during project construction; and
- **Escalation**, which accounts for anticipated increases in labour costs and material prices over the course of construction of a multi-year project.

The Planned Project Budget is the amount that the major project's management team has access to and is responsible for managing throughout the project. The entirety of the Planned Project Budget is expected to be used in its entirety throughout the project.

For large and complex projects, it is prudent to set aside additional funds for strategic risks and potential external, uncontrollable factors that may arise throughout the course of the project. This is the **Management Reserve**.

This total amount—the sum of the Planned Project Budget and the Management Reserve—is the amount that the Board of Directors and the Public Utilities Board will be asked to approve. This total amount approved by the Board of Directors and the Public Utilities will be referred to as the **Authorized Budget**.

Governance around project cost estimates includes ensuring the appropriate expertise, structures, processes, and procedures are in place to produce a reliable cost estimate. Having a rigorous process around the development of cost estimates increases the reliability of the cost estimate, which allows for increased certainty in decision-making when considering project alternatives and making the decision to approve projects.

Given the importance of a decision of this magnitude, for new and complex projects the major project's team will engage external consultants in the development of project cost estimates and major projects' team members will review the consultants' estimates. This approach ensures appropriate expertise is applied and industry norms are followed in the development of cost estimates. This practice may also reduce the level of optimism and political bias[50] that frequently causes projects to be underestimated.

The Major Projects Department's Management Team will also provide the necessary education and depth of information to ensure that the Steering Committee, RRA & Major Projects Committee, and Board of Directors understand the assumptions, inputs, and components of the cost estimates prior to making decisions based on such cost estimates.

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[50] Optimism bias occurs when the hope for a successful project leads a proponent to overestimate benefits and underestimate difficulties. Political bias, or strategic misrepresentation, is demonstrated when major project teams want their projects to be approved so they deliberately exaggerate benefits and understate costs.

14.2 Planning & Scheduling

Project planning and scheduling are tools that facilitate establishing, analyzing, and controlling the sequence and progression of work to accomplish an intended functionality, with the most efficient use of resources. The Major Projects Department will have qualified planners and schedulers to support the planning and scheduling function.

Individual projects will have their own specific project schedule that encompasses all aspects of the project. The schedule is the responsibility of the Project Manager but is housed and maintained within the Project Controls Team of the Major Projects Department. Project scheduling is informed by the schedules supplied by the various contractors and consultants working on a project.

Each project will have Basis of Schedule documentation that explains schedule inputs and assumptions, the project execution sequence and critical path, and other information, such as seasonal considerations, interfaces, regulatory and stakeholder considerations, and any potential risks to execution.

The Project Controls Team within the Major Projects Department will prepare and report against project baseline schedules. This information will facilitate oversight by informing stakeholders as to whether project execution is trending according to plan and can be used to identify risk and inform change management plans.

The Project Controls Team will also consolidate the various project schedules to form a Managerial Summary Schedule. The purpose of the Managerial Summary Schedule is to provide a high-level summary view of the portfolio of execution to aid in the management of the portfolio of work.

Governance around planning and scheduling includes ensuring the appropriate expertise, structures, processes, and procedures are in place to produce accurate schedules and facilitate monitoring against those schedules. This affords early identification of potentially concerning trends, enabling early stakeholder communication, as well as implementation of preventative and corrective actions and resourcing.

14.3 Cost Control

Cost control facilitates the measuring, monitoring, analyzing, controlling, and releasing of financial capital to projects. The Project Controls Manager is accountable for developing, maintaining, and reporting on project budgets and controlling monetary commitment[51] for the project. All members of the major project teams have responsibility for content and adherence.

Similar to schedule reporting, Planned Project Budgets are established. Actual and forecast costs are reported against the Planned Project Budget. This information facilitates early identification of deviations, allowing timely interventions to avoid or correct undesirable outcomes. Budgets are monitored and reported at both the project and portfolio levels.

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[51] A cost commitment is captured in the financial system when the financial commitment is made (e.g., upon the execution of a contract, purchase order, or service order).

The Planned Project Budget may be re-baselined to incorporate significant scope changes that have been processed and approved through the change management process.[52] Significant scope changes that drive a budget re-baseline generally result from the realization of strategic risks and are typically funded from the Management Reserve. Once re-baselined, the new budget then becomes the new reporting baseline.

Governance around cost control includes ensuring the appropriate expertise, structures, processes, and procedures are in place to monitor and control project costs. This affords early identification of potentially concerning trends, enabling early stakeholder communication, as well as implementation of preventative and corrective actions and resourcing as required.

14.4 Progress and Performance Management

Accurate progress and performance data are critical to understanding and reporting project status. The Project Controls Team produces progress and performance reports to inform whether cost and schedule targets are likely to be achieved, highlight potential concerns for investigation, and flag areas that may require prioritization or additional resourcing to mitigate less-than-desired progress. Progress and performance measurement will use metrics that are consistent with industry practice.

Governance around progress and performance management includes ensuring the appropriate expertise, structures, processes, and procedures are in place to support the identification of appropriate metrics and ongoing monitoring and reporting against those metrics. This affords early identification of potentially concerning trends, enabling early stakeholder communication, and implementation of preventative and corrective actions and resourcing as required. Appropriate performance management on projects supports ensuring that projects will deliver their intended value upon delivery and integration into Hydro's operations.

14.5 Risk Management

To complement and support the risk management efforts and escalation process described in Section 12.0, the Project Controls Team will support the identification, definition, ranking, and communication of project risks and opportunities, as well as facilitation of the individual risk response and mitigation plans. Although the Project Manager is accountable for risk within their projects, the Project Controls Team supports the risk function across the Major Projects Portfolio by ensuring consistency of risk management activities and processes. Additionally, the Project Controls Manager will Chair the Risk Working Group, providing a forum for direct communication between Project Managers, the Major Projects Department's Management Team, and the Project Controls Team.

14.6 Change Management

The Project Controls Team will support the facilitation of the change management process in a manner that is consistent with industry practice and ensures consistency across all projects and programs within the Major Projects Portfolio.

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[52] This process is further described in Section 14.6.

Members of the major project teams will identify deviations[53] and, with the support of the Project Controls Team, complete a Deviation Alert Notice[54] providing the necessary details associated with the deviation. The Deviation Alert Notice is documented in the project change register by the Project Controls Team and evaluated by the Change Control Committee to determine if it represents a change or departure that results in a change to the baseline scope, budget, or schedule. If the deviation is determined not to represent such a change, the Project Controls Team will update the project change register and communicate the decision and any required actions to the Project Manager, who is responsible for implementing any required actions.

If the deviation is determined to represent change or departure that results in a change to the baseline scope, budget or schedule, the change is reflected in project forecasts. This process ensures visibility of the likelihood and possible impact of change. To transition from a deviation notice to a change, the Project Controls Team supports the preparation of a Project Change Notice and supporting documentation,[55] which then advances to the Change Control Committee[56] for evaluation. The Change Control Committee approves or rejects Project Change Notices within its level of authority, as defined in the Major Projects Change Management Plan. Changes exceeding the Change Control Committee's level of authority advance to the Steering Committee. Changes exceeding the Steering Committee's level of authority advance to the CEO.

If the Project Change Notice is rejected by any level of decision-making authority, the Project Control Team will update the project change register and communicate the decision and any required actions to the proponent, who is responsible for implementing any required actions. Approved Project Change Notices are recorded in the project change register, which is maintained by the Project Controls Team. Depending on the nature of the change, it may result in a modification to the baseline scope, budget, or schedule (as applicable). If required, re-baselining is completed by the Project Controls Team.

Although the authorization process for approving a project change is a Project Change Notice, situations may occasionally arise where strict adherence to the documented approval workflow could result in lost opportunity and/or increased cost to a Major Project. There could also be an emergency situation that demands immediate action. If such situations arise, it is critical that the appropriate levels of approval are still provided and that some record of communicating such approval in advance of the change proceeding is obtained. Additionally, a Project Change Notice, complete with all required signatures, is still required to be completed as early as possible after the change, to ensure the change approval is clearly documented on a timely basis and all manner of records used to communicate the approval are subsequently included as support for the Project Change Notice. The Project Change Notice will also ensure all necessary follow-on actions are considered and assigned. Finally, the rationale for approving the change in advance of the Project Change Notice must be documented and included with the Project Change Notice.

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[53] A deviation is a departure of a characteristic from specified product, process, or system requirement. Specifically with respect to Major Projects, the term refers to a change, modification, or alteration from the Major Project's established guidelines, plans, or intentions.
[54] A Deviation Alert Notice is the mechanism (form) used to facilitate the processing of potential project deviations.
[55] A Project Change Notice is the mechanism (form) used to facilitate the processing of potential project changes.
[56] The Change Control Committee Terms of Reference are provided as Attachment 3.

15.0 Contracting and Procurement

The Major Projects Department is developing a Major Projects Overarching Contracting Strategy and a Major Projects Procurement Management Plan that will overview and guide contracting strategy considerations, project delivery models, and contract development. These documents include all phases of a project, including overall project management, engineering, procurement, fabrication, construction, commissioning, and handover to operations.

Contracting and procurement for Major Projects will consider the following:

- Lessons learned from other projects (Hydro's and those of other utilities);
- Industry best practices for tracking and controlling project execution;
- Compliance with Hydro's legislative obligations, including the *Public Procurement Act* and Public Utilities Board oversight;
- Satisfying commitments to Indigenous Peoples, community groups, and other stakeholders;
- Identification and allocation of risks (e.g., Hydro vs. contractor owning the risk within a contract); and
- Stakeholder oversight and approval.

All project-specific contracting strategies, whether developed by the major projects team or in partnership with the FEED consultant(s), will be designed based on a commercial risk assessment and assignment. Project delivery models (e.g., EPCM,[57] EPC,[58] progressive EPC, integrated project team) will be determined on a project-by-project basis to provide the best value based on the specific needs of the individual project.

In accordance with the Major Projects Overarching Contracting Strategy and Major Projects Procurement Management Plan, and compliance with the *Public Procurement Act*, procurement activities for all goods, materials, work and services shall be through competitive bidding unless a sole source justification has been approved. The competitive bidding process is designed to achieve the best value for Hydro, with consideration being given to technical, quality, functionality, cost-effectiveness, health, safety, and environmental factors.

Procurement and contracting practices have been developed to provide direction and guidance in the development of commercial agreements with the aim of attaining the best value for Hydro by encouraging the following:

- Maximizing the degree of interest in Hydro procurement offerings by attracting participation from qualified bidders;
- Providing as much information to the bidders as possible to enable competitive bidding based on the requirements;

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[57] Engineering, procurement, and construction management ("EPCM").
[58] Engineering, procurement, and construction ("EPC").

- Where possible and economical, awarding work on a fixed price basis; and
- Allowing the major projects team to implement sound commercial safeguards for performance, quality, and reliability.

The Major Projects Procurement Management Plan will outline methodology, direction, and guidance into contract and procurement activities supporting major projects and provide an overview of the roles and responsibilities associated with those activities.

16.0 Engineering and Project Management

16.1 Engineering

The engineering objectives for major projects are as follows:

- Ensure engineering is executed in accordance with known Hydro standards and practices and good engineering and utility practices;
- Ensure installed facilities meet Hydro's objective and performance requirements and full technical design integrity as specified by Hydro's engineering team;
- Emphasize Safety by Design and embed this philosophy into the completion of all engineering activities;
- Ensure technical quality assurance of both Major Project Department-supplied and consultant-sourced project material and construction works; and
- Consider and support operations and address operability concerns to ensure proper turnover and commissioning of the project-delivered assets.

The Major Projects Department is developing a document that will establish the overarching Engineering Management Strategy for the Major Projects Department based on Good Utility Practice. It will set the minimum expectations for standards, strategies, principles, requirements, and procedures to be implemented across all major projects. It will describe and communicate how engineering work will be executed and managed by the Major Projects Department. The Major Projects Engineering Management Strategy will outline processes for the management of engineering changes (e.g., technical queries, site queries, and engineering change notices), engineering performance, document management (e.g., operation and maintenance manuals, as-built drawings, etc.), and asset management considerations.

16.2 Project Management

The Project Management objectives for major projects are as follows:

- Ensure project management, and ultimately project execution, is performed in accordance with known Hydro standards/norms, major projects developed strategies, good project management principals, and Good Utility Practice;
- Ensure installed facilities meet the project's objectives through accountability for overall scope, schedule, quality, and cost management;

- Ensure project risks and issues are identified and mitigated as best as possible to meet the project's objectives;
- Leverage support services (e.g., project controls, procurement, safety, environment, etc.) to optimize the resources and tasks required to successfully deliver the project;
- Ensure project-specific stakeholder alignment for the Major Projects Portfolio; and
- Ensure proper turnover and commissioning of the project delivered assets.

The Major Projects Department is developing a document that will establish the overarching Project/Program Management Strategy for the Major Projects Department based on good utility and industry practice. It will set the minimum expectations for strategies, plans, requirements, and procedures to be implemented across all major projects. It will describe and communicate how projects will be managed by the Major Projects Department. The Major Projects Project/Program Management Strategy will also outline methods or tools for project management (e.g., project trackers, assumptions registers, lessons learned registers, etc.).

16.3 Quality Management

Quality management includes quality assurance and quality control processes. The Major Projects Department's Management Team takes a visible and leading role in creating and sustaining strategies, directions, performance expectations, and customer focus. The Major Projects Department's Management Team's commitment to quality is demonstrated through the objectives and expectations set in the Major Projects Quality Management Framework.

The Major Projects Department's Management Team has the responsibility for ensuring the department is properly staffed and trained to support the planning and implementation of major projects quality activities. Each project will have a Quality Management Plan that outlines the quality requirements and expectations throughout the project life cycle, as well as the reporting requirements and metrics. Once established, quality metrics, status, and issues will be reported by the Project Manager to the Quality Manager on a regular basis as part of the project's regular reporting.

Monthly updates to the Steering Committee will include quality updates for the visibility of the Executive Leadership Team as well as support in resolution of quality concerns and issues as required. Updates to the RRA & Major Projects Committee will also include quality reporting for visibility. The reports will enable the RRA & Major Projects Committee to ensure that appropriate quality management processes are in place and followed.

17.0 Workforce Planning and Management

Hydro recognizes the importance of having a workforce that supports the effective planning and execution of major projects. Having the necessary skills, experience, and competencies required to successfully plan, execute, oversee, and deliver major projects is critical.

Hydro is prioritizing hiring employees over external contractors where possible. This process supports cost management and the growth of internal skills and expertise. In early 2024, Hydro undertook an internal Expression of Interest process for roles being introduced under the Major Projects Department.

Qualified employees can be selected from this pool as roles become required. Where no internal employee has the qualifications and expertise required and where it is practical and appropriate to do so, Hydro will seek to hire qualified employees. However, where the expertise is not readily available or the circumstances do not require a long-term employee, the Major Projects Department will seek the necessary support from external consultants. In doing so, the Major Projects Department will prioritize ensuring that there is an employee (or employees) working closely with the consultant to develop the necessary skills and grow the internal expertise required such that contractor reliance is reduced. As major projects progress, it is anticipated a combination of Expressions of Interest and normal recruitment processes will be utilized. Opportunities in supporting corporate functions typically follow Hydro's normal recruitment process.

Each major project will have a Workforce Plan to support it. The Planned Project Cost Estimate will consider construction workforce requirements and labour data obtained by a reputable third party. Contractor qualifications and scopes of work will outline the necessary skills and proof of competencies required for contracted resources.

18.0 Information Management

Information Management is a term that includes the people, processes, and tools within an organization that are required to manage information throughout its life cycle, from its creation to its ultimate disposition.

With the support of the Major Projects Department, the Information Management Team is preparing an Information Management Plan to achieve the following objectives:

- To provide an effective Information Management environment where people can work collaboratively and with confidence that information is accessible, accurate, reliable, and available on a timely basis throughout the full life cycle;
- To ensure that roles and responsibilities of internal and external stakeholders (as they pertain to Information Management) are clearly defined and understood; and
- To ensure that procedures for the control and management of documentation are clearly identified and communicated.

The Information Management Plan describes how Hydro's corporate Information Management makes it possible for the Major Projects Department to manage its project information and the document control applications, processes, and procedures currently in use or planned for use to support the business initiatives and execution of major projects.

In addition to the corporate supports in place, the Major Projects Department has staff dedicated to document control, supporting the flow and control of information, training and orientation support, and maintenance of records in appropriate document control systems. The Quality Manager is accountable for major projects' document control.

The Information Management processes and procedures implemented by the Major Projects Department will support compliance with the *Management of Information Act*, *Access to Information and Protection of Privacy Act, 2015*, and the duty to document legislation.

19.0 Corporate Interfaces

Major projects will rely on corporate resources to support safety and health, financial, human resources, communications, stakeholder relations, legal, technological, regulatory, and other functional requirements. To mitigate risks associated with reliance on supporting departments, the Major Projects Department has a designated manager role that is accountable for planning, supporting, and facilitating the efforts required between the Major Projects Department and the various corporate departments. The purpose of this role is to mitigate interface risk through proactive engagement of all Hydro departments as it pertains to major projects, ensuring resource availability when required, and clarity of expectations and accountabilities between the major projects team and corporate interfaces. The major projects team has engaged with other utilities that execute major projects and has learned that similar approaches to managing corporate interfaces have been taken within those organizations.

20.0 Measuring Progress

20.1 Transparency and Reporting

To enable transparent, effective oversight of major projects, regular reporting will occur monthly for all projects. This reporting will include:

- Updates on project budget and forecast;
- Deviations on project scopes, as defined in the project charters;
- Changes in projected in-service dates;
- Updates on stakeholder engagement;
- Project risks that are ranked high and greater;
- Quality metrics;
- Safety statistics;
- Environment statistics and details on reportable incidents; and
- Other relevant project-specific information, as required.

Monthly project reports will be provided to the Major Projects Department’s Management Team, Project Sponsor, and Steering Committee. The Steering Committee also has the ability to request any additional reporting or materials it deems necessary to fulfil its mandate.

The RRA & Major Projects Committee will receive major project updates containing similar information at regularly scheduled meeting times. A similar but more condensed update will be provided to the Board of Directors at its regularly scheduled meetings. Additional reporting may be produced to inform ad hoc meetings. The RRA & Major Projects Committee also has the ability to request any additional reporting or materials it deems necessary to fulfil its mandate.

Hydro will comply with the reporting requirements established by the Public Utilities Board, making commercially sensitive and confidential information available only to the Public Utilities Board and intervening parties (upon signing a non-disclosure agreement, as per typical process). A separate, redacted version of the reports provided to the Public Utilities Board will be provided for publishing on the Public Utilities Board's website.

Regular, documented project updates will be provided to the provincial government. In addition to regular project updates, ad hoc updates will occur around project milestones, to support project financing, and as material strategic risks or change requirements emerge that the provincial government should be aware of.

20.2 Protection of Commercially Sensitive and Confidential Information

The Major Projects Department and major project teams will implement controls to ensure that commercially sensitive and confidential information remains protected. This includes, but is not limited to, details around project cost estimates and budgets, Management Reserve, certain contract provisions, etc. Protection of this information is necessary to preserve Hydro's ability to obtain the best prices and remain competitive, ultimately enabling it to achieve the best value for customers.

The major projects team will ensure that project specifics are not shared between projects by removing Project Managers and other invitees from the Change Control Committee, Risk Working Group, and Steering Committee meetings when they are not needed. Commercially sensitive and confidential information will be stored on secure sites and drives with access provided only to those who need it. Finally, reporting that will be broadly disseminated or is likely to become public will either omit updates that would disclose commercially sensitive and confidential information or the reports will be redacted to ensure such information is not visible.

20.3 Internal Audit and Advisory Services

All activities and functions of the Major Projects Department will be subject to internal audit or assessment to verify compliance with stated policy and focus on continuous improvement through the identification of both deficiencies and best practices. Hydro's Internal Audit & Advisory Services Department will identify and complete the audits or assessments.

The role of the Internal Audit & Advisory Services Department is to provide independent, objective assurance and consulting services designed to add value and improve Hydro's business activities. It helps the organization accomplish its objectives by bringing a systematic, disciplined approach to evaluate and improve the effectiveness of risk management, control, and governance processes. The Internal Audit & Advisory Services Department reports directly to the Audit Committee (a committee of the Board of Directors).

Consistently across the entirety of the Hydro organization, the scope of work of the Internal Audit & Advisory Services Department is to determine whether the organization's network of risk management, control, and governance processes as designed and represented by Hydro's leadership is adequate and functioning in a manner that ensures:

- Risks are appropriately identified and managed;
- Interaction with the various governance groups occurs as needed;
- Significant financial, managerial, and operating information is accurate, reliable, and timely;

- Employee actions comply with policies, standards, procedures, and applicable laws;
- Resources are acquired economically, used efficiently, and adequately protected;
- Programs, plans, and objectives are achieved;
- Quality and continuous improvement are fostered in the organization's control process; and
- Significant legislative or regulatory issues impacting the organization are recognized and addressed properly.

The Steering Committee or Board of Directors may also request the Internal Audit & Advisory Services Department or external auditors perform additional audits as deemed necessary.

For each audit or assessment completed, an audit report will be prepared noting all observations and findings from the audit. Results of audits are subject to management review and endorsement.

21.0 Communication and Capacity Building

Communication of governance requirements is necessary to ensure the successful implementation of this Governance Framework at the project, portfolio, and organizational levels. Hydro will ensure major projects' governance requirements are communicated and that governing groups understand their roles and responsibilities.

This Governance Framework will be presented to the Steering Committee, RRA & Major Projects Committee, and Board of Directors. Each body will also have the opportunity to review and provide feedback on the document prior to endorsing or approving it.

The Change Control Committee, Risk Working Group, and Steering Committee each have Terms of Reference outlining their roles and responsibilities and general expectations of each group.

Operationally, the requirements and processes set out in this Governance Framework are reflected in the Major Projects Department's management strategies and project plans, as shown in Figure 13.

Figure 13: Implementation of Governance

Finally, education sessions outlining the requirements of the Governance Framework will be provided for major projects staff. Sessions will also be provided for the broader Hydro organization, prioritizing those positions and departments that may be affected by it or expected to comply with it.

As Hydro progresses through major projects, the Director of Major Projects & Asset Management will assess whether additional resources are required to support governance processes. Additionally, the Internal Audit & Advisory Services Department will support the Major Projects Department in the implementation of governance practices and will undertake periodic reviews and audits to confirm compliance with the Governance Framework.

22.0 Review Process

This Governance Framework will be reviewed at least annually by the Director of Major Projects & Asset Management; the Steering Committee; and the RRA & Major Projects Committee. The review will consider the functionality and effectiveness of the Governance Framework, ensuring it provides for appropriate accountability and oversight, evolutions in Hydro's maturity with Major Projects, completion of management strategies and other supporting documents, governance-related risks, and lessons learned throughout the governance of Major Projects in the previous year.

Proposed changes that would be considered a major revision (e.g., adding/removing requirements or sections, updates that significantly alter the intent or scope of the Governance Framework) to the Governance Framework will be reviewed and approved by the Board of Directors.

Major Projects

Governance Framework

Attachment 1: Major Projects Steering Committee Terms of Reference

NLH Doc. No. NLH-MPM-00000-PM-REF-0001-01

Major Projects

Steering Committee Terms of Reference

NLH Doc. No. NLH-MPM-00000-PM-REF-0001-01

Comments: The Major Projects Steering Committee Terms of Reference defines the agreed purpose, responsibilities, composition, and expectations of the Major Projects Steering Committee.	Total # of Pages (including Cover): 8
Revision B0 was Approved by Newfoundland and Labrador Hydro's Board of Directors on February 25, 2025	

Revision	Date (DD-MMM-YYYY)	Issue Reason	Prepared By Lead, Strategic Initiatives	Approved By Director, Major Projects & Asset Management	Approved by Vice President, Hydro Engineering & NLSO	Approved by President & CEO
B0	5-Mar-2025	Use	Ann Malone	Gail Randell	Robert Collett	Jennifer Williams

These signatures are required to confirm compliance with Major Projects Department procedures. This document cannot be finalized or distributed without this approval. Any version of this document without these signatures is not considered final.

Contents

List of Appendices

1.0 Background

Newfoundland and Labrador Hydro (Hydro) has established a Major Projects Steering Committee (Steering Committee) as part of its broader framework to support the effective governance of major projects. The Steering Committee provides a forum for the major project teams to obtain approvals and provide updates related to current progress; identify challenges; raise issues; support risk mitigations; and seek input, guidance, and advice on matters of significance.

This Steering Committee Terms of Reference defines the agreed purpose, responsibilities, composition, and expectations of the Steering Committee.

2.0 Purpose

As is typical for a committee of this nature, the Steering Committee is not responsible for managing major projects; rather, its purpose is to:

- Provide strategic oversight and guidance during all phases of major projects;
- Ensure two-way communication across Hydro’s Executive Leadership Team regarding the impact that major projects may have on matters such as risk management, resourcing, and operations across the rest of Hydro and vice versa; and
- Support and provide efficient and effective decision-making.

3.0 Responsibilities

The responsibilities of the Steering Committee include:

- Reviewing project complexity assessments and determine whether projects are major projects;
- Ensuring the Major Projects Portfolio remains aligned with Hydro’s mandate, vision, values, and strategic goals;
- Prioritizing projects within the Major Projects Portfolio;
- Approving project changes as outlined in the Major Projects Change Management Plan;
- Reviewing all risks ranked as high and greater and ensuring appropriate risk management strategies are in place for high and greater strategic risks;[1]
- Supporting stakeholder management; and
- Offering guidance and advice on specific items with high significance.

[1] Tactical risks ranked as low and medium and strategic risks ranked as low will be managed by the Project Manager. Tactical risks ranked as high and greater will be managed by the Major Projects Risk Working Group and communicated to the Steering Committee for awareness. Strategic risks ranked as medium and greater will be communicated to the Steering Committee and the Steering Committee will approve risk management strategies for such risks.

As Hydro advances through various major projects, the responsibilities of the Steering Committee are subject to change at the discretion of the Steering Committee to ensure its ability to effectively achieve its fundamental purpose as outlined herein.

4.0 Steering Committee Composition

The Steering Committee is comprised of Hydro's Executive Leadership Team, including all Vice Presidents and the CEO. The inclusion of the full Executive Leadership Team on the Steering Committee is reflective of Hydro's current maturity related to the planning, authorizing, executing, and delivery of Major Projects. As Hydro advances various major projects, project teams become more experienced, and work of this nature becomes embedded in Hydro's day-to-day business operations, the composition and responsibilities of the Steering Committee may evolve and will ensure the effectiveness of the Steering Committee and maintain the appropriate level of governance.

The inclusion of the full Executive Leadership Team at this stage of Hydro's major projects activities supports both major projects and the rest of Hydro's operations as follows:

- Major projects benefit from the collective leadership, resources, experience, and strategic oversight of the entire Executive Leadership Team;
- The Executive Leadership Team's visibility into major projects ensures planning, strategic initiatives, risk management, and day-to-day operations are undertaken with knowledge of relevant major projects' activities;
- Facilitates early and comprehensive identification and resolution of potential risks and issues; and
- Facilitates efficient and effective decision-making related to major projects due to the ongoing involvement of executive-level decision-makers.

5.0 Meetings

5.1 Frequency

The Steering Committee will meet at least monthly. Additional meetings may be arranged on an ad hoc basis.

5.2 Agenda

Meeting agendas should be circulated at least a week in advance of regularly scheduled monthly meetings and as early as possible in advance of additional ad hoc meetings.

A sample draft agenda for regular monthly meetings is provided as Appendix A.

5.3 Attendees

Meetings will be attended by:

- Steering Committee members;
- Project Sponsors;
- Director, Major Projects & Asset Management;
- Director, Internal Audit & Advisory Services;[2]
- Project Managers;
- Project Coordinator, Major Projects; and
- Other advisors as required or requested by the Steering Committee.

If a Steering Committee member cannot attend a meeting, they will delegate their attendance to a member of the Senior Leadership Team. It is the responsibility of the delegate attendee to ensure relevant materials and information are communicated back to the Steering Committee member.

5.4 Chair

Meetings will be chaired by the Director of Major Projects & Asset Management or an appropriate delegate.

5.5 Quorum

For a meeting to be considered official and to enable decision-making, a quorum of five Steering Committee members is required. Delegate attendees cannot be considered as Steering Committee members in attendance for the purpose of determining if a quorum is met.

5.6 Confidentiality of Commercially Sensitive Information

To preserve the confidentiality of commercially sensitive information, Project Sponsors, Project Managers, and other special invitees will only attend the portion of the meeting that applies to their projects. To ensure that commercially sensitive information is shared only with those for whom it is relevant and necessary, such information will be provided during in-camera sessions attended by only the necessary Steering Committee members and meeting attendees.

5.7 Meeting Minutes

Meeting minutes will be recorded to document the discussion and direction provided, including decisions, the basis for decisions, and action items.

Meeting minutes will be circulated for review at least one week in advance of the next regularly scheduled monthly meeting and will be approved at the next regularly scheduled monthly meeting. For

[2] The Director of Internal Audit & Advisory Services will be invited to all Steering Committee meetings but is not a Steering Committee member and does not participate in decision-making. Their attendance may be delegated at their discretion.

example, January meeting minutes will be circulated for review at least one week in advance of the February meeting and will be approved at the February meeting.

6.0 Decision-Making

Decisions may be made by the Steering Committee at meetings where a quorum has been met. However, it is recognized that certain decisions may require particular Steering Committee members. For example, decisions related to project financing require the input and approval of the Vice President, Chief Financial Officer. To ensure efficiency and effectiveness of decision-making, the Director of Major Projects & Asset Management will inform the Steering Committee of any decisions anticipated to be made at the meeting at least a week in advance of regularly scheduled monthly meetings to ensure the necessary decision-makers are either in attendance at the meeting or alternate arrangements are made.

7.0 Reporting

The Steering Committee will receive monthly project reports that include, at a minimum:

- Updates on project budget and forecast;
- Deviations on project scopes, as defined in the project charters;
- Changes in projected in-service dates;
- Updates on stakeholder engagement;
- Project risks that are ranked high and greater;
- Quality metrics;
- Safety statistics;
- Environment statistics; and
- Other relevant project-specific information, as required.

The reports will be circulated by email and reviewed by the Steering Committee prior to regularly scheduled monthly meetings.

Additional reports or materials may be produced at the request of the Steering Committee or to inform ad hoc meetings.

Meeting materials will be stored in a secure location accessible to all members of the Steering Committee.

8.0 Changes to the Terms of Reference

The Steering Committee Terms of Reference will be reviewed at least annually.

Major Projects

Steering Committee Terms of Reference

Appendix A: Sample Draft Meeting Agenda

1. Introduction

a. Attendance/Confirmation of Quorum

b. Review Agenda

c. Approval of Minutes

d. Actions Arising (from previous Steering Committee meetings)

2. Business Updates

3. Project-Specific Updates

a. Project 1

i. Review Monthly Project Report

ii. Overall Project Status

iii. Scope, Budget, Schedule Status

iv. Milestone Review

v. Review and Approval of Material Project Changes

vi. Risk Review

vii. Challenges/Barriers

viii. Other Items as Necessary

ix. In-Camera Session (to address commercially sensitive matters)

b. Project 2

c. Project 3

d. …

4. Major Projects Department Updates

5. Action Items

6. Confirm Date and Time of Next Meeting

Major Projects

Governance Framework

Attachment 2: Major Projects Risk Working Group Terms of Reference

NLH Doc. No. NLH-MPM-00000-PM-REF-0003-01

Major Projects

Risk Working Group Terms of Reference

NLH Doc. No. NLH-MPM-00000-PM-REF-0003-01

Comments: The Major Projects Risk Working Group Terms of Reference defines the agreed purpose, responsibilities, composition, and expectations of the Major Projects Risk Working Group.	Total # of Pages (including Cover): 9
Revision B0 was Approved by Newfoundland and Labrador Hydro's Board of Directors on February 25, 2025	

B0	5-Mar-2025	Use	Ann Malone	Gail Randell	Robert Collett	Jennifer Williams
Revision	**Date** (DD-MMM-YYYY)	**Issue Reason**	**Prepared By** Lead, Strategic Initiatives	**Approved By** Director, Major Projects & Asset Management	**Approved by** Vice President, Hydro Engineering & NLSO	**Approved by** President & CEO
These signatures are required to confirm compliance with Major Projects Department procedures. This document cannot be finalized or distributed without this approval. Any version of this document without these signatures is not considered final.						

Contents

List of Appendices

1.0 Background

The Major Projects Department has established a Major Projects Risk Working Group (Risk Working Group) as part of its broader framework to support the effective governance of Major Projects as outlined in the Major Projects Governance Framework and the Major Projects Risk Management Strategy. The Risk Working Group provides a forum for the Major Projects Department Management Team to comprehensively evaluate risks and ensure effective management and communication of risks. The Risk Working Group enables the Major Projects Department and the Major Projects Steering Committee (Steering Committee) to make risk-informed decisions, including prioritization of projects and resources.

This Risk Working Group Terms of Reference defines the agreed purpose, responsibilities, composition, and expectations of the Risk Working Group.

2.0 Purpose

The purpose of the Risk Working Group is to:

- Provide a comprehensive, management-level view to the Major Projects Department's project and program risk management;
- Support, as required, Program and Project Managers in ranking and managing project- and program-level risks;
- To advise the Steering Committee by ensuring they have awareness of all risks ranked as high and greater and proposing appropriate risk management strategies for strategic risks; and
- To integrate risk management of major projects with corporate risk management practices through participation in Hydro's corporate Enterprise Risk Management (ERM) process.

3.0 Scope

The scope of the Risk Working Group includes all project- and program-related risks across all major projects under the accountability of the Major Projects Department. The Risk Working Group does not process change associated with risk management strategies that impact project and program cost, schedule, and scope. Such risk management strategies must follow the appropriate change management processes and obtain the appropriate authorizations, as outlined in the Major Projects Change Management Plan.

4.0 Responsibilities

The responsibilities of the Risk Working Group include:

- Understanding project and program risks and interdependencies between projects and programs;
- Proactively identifying and ranking risks, including corporate risks, that could impact Hydro's ability to deliver the goals and objectives of its Major Projects Portfolio;

- Analyzing and prioritizing risks, providing a clear understanding of their potential impacts and likelihoods;
- Reviewing tactical risks ranked as high and greater and approving appropriate risk management strategies for such risks;
- Reviewing all escalated project risks from a portfolio level to identify risk impacts between projects, risk trends, emerging risks, and risks that may impact Hydro corporately;
- Developing recommended risk management strategies for high and greater strategic risks and proposing them to the Steering Committee;
- Monitor and report on risk management strategies;
- Ensuring alignment of project and program risk processes and documentation with Hydro's corporate risk processes and documentation; and
- Promoting corporate understanding of Major Projects' risks and major projects' understanding of corporate risks through direct participation in Hydro's corporate ERM processes.

5.0 Risk Working Group Composition

The composition of the Risk Working Group reflects the project, program, and portfolio knowledge of the Major Projects Department's Management Team and the various project managers that work closest with the major projects' teams.

The Risk Working Group is comprised of the following positions:

- Director, Major Projects & Asset Management
- Senior Manager, Major Projects Project Management & Engineering
- Senior Manager, Major Projects Commercial
- Manager, Major Projects Corporate Interface
- Manager, Major Projects Project Controls (Chair)
- Specialist, Major Projects Risk

As the Major Projects Department advances various Major Projects and project teams become more experienced, the composition and responsibilities of the Risk Working Group may evolve to ensure the effectiveness of the Risk Working Group.

6.0 Meetings

6.1 Frequency

The Risk Working Group will meet at least monthly. Additional meetings may be arranged on an ad hoc basis.

6.2 Agenda

Meeting agendas will be circulated at least a week in advance of regularly scheduled monthly meetings and as early as possible in advance of additional ad hoc meetings.

A sample draft agenda for regular monthly meetings is provided in Appendix A.

6.3 Attendees

Meetings will be attended by:

- Risk Working Group members;
- A representative of the Internal Audit & Advisory Services Department;[1] and
- Other advisors as required or requested by the Risk Working Group (e.g., Safety Advisor, Project Managers, Operations, etc.).[2]

Standing, optional meeting invitations will be provided for Project Sponsors and the Lead, Financial & Enterprise Risk Management.

If a Risk Working Group member cannot attend a meeting, they will delegate their attendance. It is the responsibility of the delegate attendee to ensure relevant materials and information are communicated back to the Risk Working Group member.

6.4 Chair

The Risk Working Group is chaired by the Major Projects Project Controls Manager, who holds responsibility for risk processes within the Major Projects Department Structure.

6.5 Quorum

For a meeting to be considered official and to enable decision-making, a quorum of four Risk Working Group members is required. Delegate attendees cannot be considered as Risk Working Group members in attendance for the purpose of determining if a quorum is met.

6.6 Confidentiality of Commercially Sensitive Information

To preserve the confidentiality of commercially sensitive information, Project Sponsors, Project Managers, and other special invitees will only attend the portion of the meeting that is applicable to their projects. Meeting Documentation

[1] The Internal Audit & Advisory Services Department will not participate in decision-making. Their attendance is for the purpose of hearing the discussion to understand the risks and appropriately inform audit planning.

[2] A senior representative from regulatory, safety, human resources, stakeholder engagement, corporate communications, legal, and each of the operational areas will be identified to attend meetings as required based on the nature of the risks to be discussed.

Meetings will be documented via an updated Risk Register, which is owned and maintained by the Risk Working Group. Additional notes and action items will be recorded as necessary.

7.0 Decision-Making

The Risk Working Group identifies strategic risks and makes recommendations for risk management strategies to the Steering Committee (i.e., for strategic risks, decision-making responsibility resides with the Steering Committee).

For tactical risks, the Risk Working Group reviews tactical risks ranked as high and greater and approves appropriate risk management strategies for such risks.[3] Decisions can be made at meetings where a quorum has been met and when a majority of the Risk Working Group members are in agreement. Decisions must be aligned with the appropriate personnel (e.g., prior to approval, risk management strategies associated with safety risk must be aligned with the Safety Lead).

Risk management strategies that drive a project change must go through the appropriate change management processes and obtain the appropriate authorizations, as outlined in the Major Projects Change Management Plan.

8.0 Reporting

8.1 Project- and Program-Specific Risk Reporting

Project- and program-specific risk reporting will be included in regular monthly project and program reports. Such reports will be provided to the Program Sponsor and the Steering Committee monthly.

8.2 Comprehensive Risk Reporting

The Director of Major Projects & Asset Management will provide a risk update at the regular monthly meetings of the Steering Committee. Monthly updates will highlight any new emerging risks, changes in the ranking of previously identified risks, and any potential concerns or issues with implemented risk management strategies. Similar risk updates will also be included in regular updates to the RRA[4] & Major Projects Committee of the Board of Directors.

8.3 Integration with Corporate Risk Reporting

On a semi-annual basis, the Risk Working Group will meet with the Corporate Risk Team to overview top risks and risk management strategies. Such information will consolidate into Hydro's corporate risk reporting to the Governance Committee, a sub-committee of Hydro's Board of Directors.

Also on a semi-annual basis, the Senior Manager, Major Projects Project Management & Engineering and the Senior Manager, Major Projects Commercial will participate in corporate Management Risk

[3] Project Managers have authority to identify and implement risk management strategies for risks ranked below high.
[4] Reliability and Resource Adequacy (RRA).

Committees. They will report back to the Risk Working Group any corporate risks that may impact major projects, and such risks will then become incorporated into regular comprehensive risk reporting.

8.4 Other Reporting

Additional reports or materials may be produced at the request of management, the Major Projects Steering Committee, the RRA & Major Projects Committee of the Board of Directors, or to inform ad hoc meetings.

9.0 Changes to the Terms of Reference

The Risk Working Group Terms of Reference will be reviewed at least annually.

Major Projects

Risk Working Group Terms of Reference

Appendix A: Sample Draft Meeting Agenda

	Major Projects Risk Working Group Terms of Reference				
NLH Doc. No.	**NLH-MPM-00000-PM-REF-0003-01**	**Revision**	**B0**	**Page**	**A-1**

1. Introduction
   a. Attendance/Confirmation of Quorum
   b. Review Agenda
   c. Approval of Risk Register
   d. Actions Arising (from previous Major Projects Risk Working Group meetings)
2. Project- and Program-Specific Risk Review
   a. Project 1
      i. Identification and ranking of new risks
      ii. Determine appropriate risk management strategies
      iii. Identification of changes in previously-ranked risks
      iv. Review effectiveness of risk management strategies
      v. Discussion of corporate risks
      vi. Items that require escalation to the Major Projects Steering Committee for decision-making/resolution
      vii. Other items as necessary
   b. Project 2
   c. Project 3
   d. …
3. Major Projects Departmental/Portfolio Risks
4. Corporate Risk Discussion
5. Action Items
6. Confirm Date and Time of Next Meeting

Major Projects

Governance Framework

Attachment 3: Major Projects Change Control Committee Terms of Reference

NLH Doc. No. NLH-MPM-00000-PM-REF-0002-01

newfoundland labrador hydro

Major Projects

Change Control Committee Terms of Reference

NLH Doc. No. NLH-MPM-00000-PM-REF-0002-01

Comments: The Major Projects Change Control Committee Terms of Reference defines the agreed purpose, responsibilities, composition, and expectations of the Major Projects Change Control Committee.	Total # of Pages (including Cover): 8
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B0	5-Mar-2025	Use	Ann Malone	Gail Randell	Robert Collett	Jennifer Williams
Revision	**Date** (DD-MMM-YYYY)	**Issue Reason**	**Prepared By** Lead, Strategic Initiatives	**Approved By** Director, Major Projects & Asset Management	**Approved by** Vice President, Hydro Engineering & NLSO	**Approved by** President & CEO
These signatures are required to confirm compliance with Major Projects Department procedures. This document cannot be finalized or distributed without this approval. Any version of this document without these signatures is not considered final.						

	Major Projects Change Control Committee Terms of Reference				
NLH Doc. No.	**NLH-MPM-00000-PM-REF-0002-01**	**Revision**	**B0**	**Page**	**i**

Contents

List of Appendices

1.0 Background

The Major Projects Department has established a Major Projects Change Control Committee (Change Control Committee) as part of its broader framework to support the effective governance of Major Projects. The Change Control Committee provides a forum for the Major Projects Department's Management Team to comprehensively evaluate proposed project and program changes and ensure effective management and communication of such changes. The Change Control Committee enables the Major Projects Department and the Major Projects Steering Committee (Steering Committee) to make informed decisions and ensure appropriate allocation and communication of impacts and resources.

This Change Control Committee Terms of Reference defines the agreed purpose, responsibilities, composition, and expectations of the Change Control Committee.

2.0 Purpose

The purpose of the Change Control Committee is to:

- Provide a comprehensive, management-level view to the Major Projects Department's project and program change management;
- Ensure that changes and change management practices remain in alignment with project and program objectives and requirements;
- Manage and oversee changes to project and program scope, schedule, budget, and quality (subject to the appropriate authorization levels as outlined in the Major Projects Change Management Plan); and
- Ensure integration and communication of changes and change management practices to Hydro's corporate interfaces as required to support corporate operations and optimal resource management.

3.0 Scope

The scope of the Change Control Committee includes all project- and program-related changes impacting budget, scope, schedule, and quality (as defined in the Major Projects Change Management Plan) across all Major Projects under the accountability of the Major Projects Department.

4.0 Responsibilities

The responsibilities of the Change Control Committee include:

- Evaluating, approving, and monitoring changes within a project (subject to the appropriate authorization levels as outlined in the Major Projects Change Management Plan);
- Ensuring changes that drive risk or are driven by risk mitigation strategies are appropriately communicated and coordinated with the Major Projects Risk Working Group;
- Ensuring appropriate communication of changes and change management practices to Hydro's corporate interfaces, as required;

- Understanding project and program changes and interdependencies and secondary impacts ("ripple effects") between projects and programs, including their impacts on ongoing operations and maintainability;
- Analyzing and prioritizing changes, providing a clear understanding of potential impact; and
- Promoting corporate understanding of project and program changes and major projects' understanding of the corporate impact of change.

5.0 Change Control Committee Composition

The composition of the Change Control Committee reflects the project, program, and portfolio knowledge of the Major Projects Department's Management Team and the financial and legal resources required to advise as to the legal and corporate financial impact on projects.

The Change Control Committee is comprised of the following positions:

- Director, Major Projects & Asset Management
- Director, Strategic Finance, Treasury, and Insurance
- Senior Manager, Major Projects Project Management & Engineering
- Senior Manager, Major Projects Commercial
- Manager, Major Projects Project Controls
- Senior Legal Counsel

As the Major Projects Department advances various major projects, project teams become more experienced, and work of this nature becomes embedded in Hydro's day-to-day business operations, the composition and responsibilities of the Change Control Committee may evolve to ensure the effectiveness of the Change Control Committee.

6.0 Meetings

6.1 Frequency

The Change Control Committee will meet at least monthly. Additional meetings may be arranged on an ad hoc basis.

6.2 Agenda

Meeting agendas outlining proposed changes will be circulated at least a week in advance of regularly scheduled monthly meetings and as early as possible in advance of additional ad hoc meetings.

A sample draft agenda for regular monthly meetings is provided in Appendix A.

6.3 Attendees

Meetings will be attended by:

- Change Control Committee members;
- Project Managers;
- A representative of the Internal Audit & Advisory Services Department;[1]
- A representative of the operational area responsible for operating and maintaining the assets once the project is complete and transitioned to operations;[2] and
- Other advisors as required or requested by the Change Control Committee (e.g., cost control, regulatory, safety, operations, etc.), as their input and/or alignment are required to appropriately process changes.[3]

Standing, optional meeting invitations will be provided for Project Sponsors.

If a Change Control Committee member cannot attend a meeting, they will delegate their attendance. It is the responsibility of the delegate attendee to ensure relevant materials and information are communicated back to the Change Control Committee member.

6.4 Chair

Change Control Committee meetings will be chaired by the Director of Major Projects & Asset Management.

6.5 Quorum

For a meeting to be considered official and to enable decision-making, a quorum of four Change Control Committee members is required. Delegate attendees cannot be considered as Change Control Committee members in attendance for the purpose of determining if a quorum is met.

6.6 Confidentiality of Commercially Sensitive Information

To preserve the confidentiality of commercially sensitive information, Project Sponsors, Project Managers, and other special invitees will only attend the portion of the meeting that is applicable to their projects.

6.7 Meeting Documentation

Meetings will be documented via updated Project Change Logs, which are maintained by the Manager of Major Projects Project Controls. Additional notes and action items will be recorded as necessary.

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[1] The Internal Audit & Advisory Services Department will not participate in decision-making. Their attendance is for the purpose of hearing the discussion to understand the nature of proposed changes and appropriately inform audit planning.
[2] These individuals will attend if changes pertaining to their operational assets are to be discussed at that meeting.
[3] A senior representative from regulatory, safety, human resources, stakeholder engagement, corporate communications, legal, and each of the operational areas will be identified to attend meetings as required based on the nature of the proposed changes to be discussed.

7.0 Decision-Making

The Change Control Committee will make decisions and approve changes within the authorization limits as outlined in the Major Projects Change Management Plan.

8.0 Reporting

Change reporting will be included in regular monthly project and program reports. Such reports will be provided to the Project Sponsor and the Steering Committee monthly.

The Director of Major Projects & Asset Management will provide an update on material changes at the regular monthly meetings of the Steering Committee. Similar updates will also be included in regular updates to the RRA[4] & Major Projects Committee of the Board of Directors. Additional reports or materials may be produced at the request of management, the Steering Committee, the RRA & Major Projects Committee of the Board of Directors, or to inform ad hoc meetings of the Change Control Committee.

Changes that introduce material risk or are implemented as part of a risk management strategy will be managed and reported through the Major Projects Risk Working Group and Hydro's corporate Enterprise Risk Management processes, as provided for in the Major Projects Risk Management Strategy.

9.0 Changes to the Terms of Reference

The Change Control Committee Terms of Reference will be reviewed at least annually.

[4] Reliability and Resource Adequacy (RRA).

Major Projects

Change Control Committee Terms of Reference

Appendix A: Sample Draft Meeting Agenda

	Major Projects Change Control Committee Terms of Reference				
NLH Doc. No.	**NLH-MPM-00000-PM-REF-0002-01**	**Revision**	**B0**	**Page**	**A-1**

1. Introduction
    a. Attendance/Confirmation of Quorum
    b. Review Agenda
    c. Approval of Change Log
    d. Actions Arising (from previous Change Control Committee meetings)
2. Presentation of proposed changes
    a. Project 1
        i. Overview of proposed change
        ii. Anticipated impact of proposed change (project, portfolio, and corporate)
        iii. Approval/denial of proposed change (including rationale)
        iv. Other items as necessary
    b. Project 2
    c. Project 3
    d. …
3. Corporate Change Discussion
4. Action Items
5. Confirm Date and Time of Next Meeting

Schedule 1, Attachment 2

Hydrology and Feasibility Study for Potential Bay d'Espoir Hydroelectric Generating Unit No. 8 – Addendum Report

Hatch Limited

Newfoundland and Labrador Hydro
Hydrology and Feasibility Study for Potential Bay d'Espoir
Hydroelectric Generating Unit No. 8 2025 Update
H375556

Addendum Report

Hydrology and Feasibility Study for Potential Bay d'Espoir Hydroelectric Generating Unit No. 8

H375556-0000-2B0-230-0001

			Mathur, Pulkit		
2025-03-19	**B**	**Client Review**	**T. Olason / P. Mathur**	**M. Rosales**	**T. Olason**
2025-03-17	**A**	**Internal Review**	**T. Olason / P. Mathur**	**M. Rosales**	**T. Olason**
DATE	**REV.**	**STATUS**	**PREPARED BY**	**CHECKED BY**	**APPROVED BY**

Important Notice to Reader

This report has been prepared by Hatch Ltd. ("Hatch") for the sole and exclusive use of Newfoundland and Labrador Hydro (the "Client") for the purpose of assisting the management of the Client in making decisions with respect to the Bay d'Espoir Hydroelectric Development. This report must not be used by the Client for any other purpose, or provided to, relied upon or used by any other person. Any use of or reliance upon this report by another person is done at their sole risk and Hatch does not accept any responsibility or liability in connection with that person's use or reliance.

This report contains the expression of the opinion of Hatch using its professional judgment and reasonable care based upon information available and conditions existing at the time of preparation of this report, and information made available to Hatch by the Client or by certain other parties on behalf of the Owner (the "Client or Other Information").

The use of or reliance upon this report is subject to the following:

1. This report is to be read in the context of and subject to the terms of the relevant services agreement dated February 25, 2025, between Hatch and the Client (the "Agreement"), including any methodologies, procedures, techniques, assumptions and other relevant terms or conditions specified in the Hatch Agreement.
2. This report is meant to be read as a whole, and sections of the report must not be read or relied upon out of context.
3. Unless expressly stated otherwise in this report, Hatch has not verified the accuracy, completeness or validity of any information provided to Hatch by or on behalf of the Client and Hatch does not accept any liability in connection with such information.
4. Conditions may change over time (or may have already changed) due to natural forces or human intervention, and Hatch does not accept any responsibility for the impact that such changes may have on the accuracy or validity of the opinions, conclusions and recommendations set out in this report.

Table of Contents

List of Tables

List of Figures

Executive Summary

The objective of the study was to update an earlier study by Hatch on the impact of the addition of Bay d'Espoir Unit 8 on the hydroelectric generation and operation of the Bay d'Espoir reservoir system. The scope of work included background data review; hydrological analysis; and power and energy model (Hatch Vista DSS) analysis. This study examined the effects of updated hydrology, the 2024 reference load forecast and recent data on frazil ice effects.

The study confirms the results of the earlier study, but the hydrology and load forecast caused a small decrease in firm and average energy estimates.

The firm energy estimate for the Bay d'Espoir system with Unit 8 is 294 MWc, down from the earlier estimate of 297.5 MWc.

The simulated average annual energy of the existing Bay d'Espoir system is 3,359.74 GWh. With the addition of Unit 8, it increases to 3,381.19 GWh, due to higher efficiency of the new unit and some spill capture.

The simulated average annual energy of the Bay d'Espoir plant is 2,613.56 GWh. The simulated average annual energy of the plant with the addition of Unit 8 is 2,646.46 GWh, an increase of 1.26 percent.

With the addition of Unit 8, the simulated hourly generation of the Bay d'Espoir plant increases 18.6 percent of the time and decreases 27.9 percent of the time. The increased generation occurs during on-peak hours while the decreased generation occurs during off-peak hours.

The study also confirmed the optimum utilization of the new unit. It will be the most efficient unit in the plant and should be base loaded.

The simulated hourly optimized generation capacity increase at the Bay d'Espoir plant is 150.1 MW with addition of Unit 8. This is less than the 154.4 MW capacity of the new unit because, although the model utilizes the full capacity of Unit 8, it optimizes the total Bay d'Espoir plant output to meet the defined firm load while maximizing energy. The increase in simulated on-peak generation is at the expense of simulated off-peak generation. This condition is a result of the Bay d'Espoir system being modelled in isolation for the purposes of this analysis. Through optimization of Hydro's full hydraulic resources, which was not simulated as part of this study, resources can likely be managed to fully mitigate the potential for energy shortfall from the Bay d'Espoir system to achieve an optimized increase in maximum generation equal to the full unit capability of 154.4 MW.

With addition of Unit 8, simulated Bay d'Espoir plant efficiency increases are in the range of 0.16 to 1.83 percent, with an average of 0.76 percent.

The North Salmon bypass spillway is used only 2.5 percent of the time in the simulation of the existing system, and 3.0 percent of the time with addition of Unit 8. The bypass may be used during periods of high inflow that exceed the capacity flow at the Upper Salmon plant and cannot be stored; periods when the Upper Salmon plant is shut down; and when necessary to delay water from reaching the Long Pong reservoir to provide more time to generate water out of the Long Pond reservoir when the Long Pond water level is high.

There is a slight loss of simulated efficiency at Upper Salmon plant with addition of Bay d'Espoir Unit 8. This loss occurred 17.98 percent of the time.

The information provided by Hydro on the hydromechanical equipment, head losses and tailwater does not indicate any physical restrictions to prevent Unit 8 from attaining 154.4 MW, or the Bay d'Espoir plant from attaining its full rated capacity, as long as there is water in the reservoir.

This study also re-examined the end-of-November elevation ranges and reconfirmed the range from the earlier study, that is, the large storage reservoirs in the system to optimize Bay d'Espoir system generation in the winter months while allowing room for possible early winter high flow.

- Victoria: 323.59 m to 325.39 m
- Meelpaeg: 271.72 m to 272.18 m
- Long Pond: 182.22 m to 182.25 m.

If levels at the end of November are lower than the recommended ranges, the system may not be able to do as much peaking in winter.

1. Introduction

In December 2020, Hatch Ltd. (Hatch) completed a hydrology and feasibility study for a potential new generating unit at the Bay d'Espoir Hydroelectric Generating Station for Newfoundland and Labrador Hydro (Hydro). In January 2025 Hydro asked Hatch to refresh the 2020 study with the most recent assumptions and hydrology, and to confirm its validity as Hydro has since determined the need to construct the new unit.

This addendum to the 2020 report documents the scope of work, background information, methodology, results, conclusions and recommendations from the 2025 update.

1.1 Objective

The objective of the current study is to update the 2020 study on the impact of the addition of Bay d'Espoir Unit 8 on the hydroelectric generation and operation of the Bay d'Espoir reservoir system.

1.2 Scope of Work

The scope of work includes the following components.

- Review and update assumptions and inputs used in the original 2020 study, including frazil ice assumptions, updated hydrology and Hydro's latest load forecasts.
- Re-run final set of 2020 runs to evaluate the impact.
- Review and recommend end of November targets water levels for major reservoirs in the Bay d'Espoir system.
- Addendum report.

For reference, the 2020 study considered the following issues.

- Potential operating procedure modifications, following the addition of Unit 8.
- Average annual energy of the Bay d'Espoir Hydroelectric Generating Station.
- Firm annual energy of the Bay d'Espoir Hydroelectric Generating Station.
- Average monthly energy on-peak and off-peak of the Bay d'Espoir Hydroelectric Generating Station.
- Firm monthly energy on-peak and off-peak of the Bay d'Espoir Hydroelectric Generating Station.
- Impact on the operation of Upper Salmon Hydroelectric Generating Station.
- Operations to control frazil ice at the generating stations in the system.

- Target storage of the Bay d’Espoir system reservoirs in advance of the winter operating season.
- Impact on efficiency for Bay d’Espoir Hydroelectric Generating Station.
- Inclusion of fish compensation requirements at Granite Canal Hydroelectric Generating Station and fisheries releases at Pudops Dam for Grey River and Burnt Spillway for White Bear River.

2. Data Review and Updates

Study inputs and assumptions are discussed in detail in the earlier report by Hatch (2020). For this update to the study, several key inputs and assumptions were revisited and updated. These are discussed in more detail below.

2.1 Unit Characteristics

The new facility will utilize the existing powerhouse forebay and does not require the construction of any additional dams. Unit 8 will use a draft tube-like Unit 7 with a minor modification to reduce head losses. The generating unit equipment will be designed to modern standards. As recommended by SLI (2018a) and as was modelled in the 2020 study, the unit will have a nominal combined efficiency of 0.916 and a transformer efficiency of 0.99. The penstock loss at capacity (154.4 MW) is 5.81 m. A comparison of the modelled efficiency curves for Unit 7 and the new Unit 8 is shown in Figure 2-1 below.

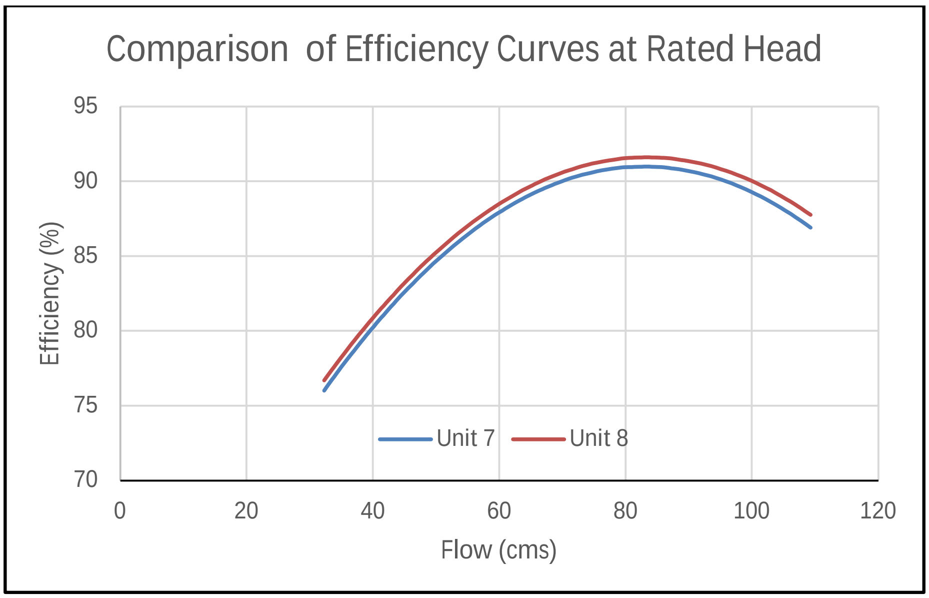

Figure 2-1: Comparison of Unit 7 and 8 Efficiency

2.2 Tailwater Curve

A tailrace channel expansion is recommended in the SLI (2018b) report, to minimize any increase in tailwater elevation that could result from increased plant discharge with the addition of Unit 8. In the 2020 study, it was assumed that the tailrace channel expansion recommended by SLI (2018b) with the addition of Unit 8 will be implemented. Therefore, the tailwater relationship in Vista was adjusted such that the tailwater level at the full discharge of the expanded plant is the same as the level at full discharge of the existing plant. The tailwater relationship used in the 2020 study will be used for the current study. A comparison of the modelled Long Pond tailwater curves for with and without Unit 8.is shown in Figure 2-2.

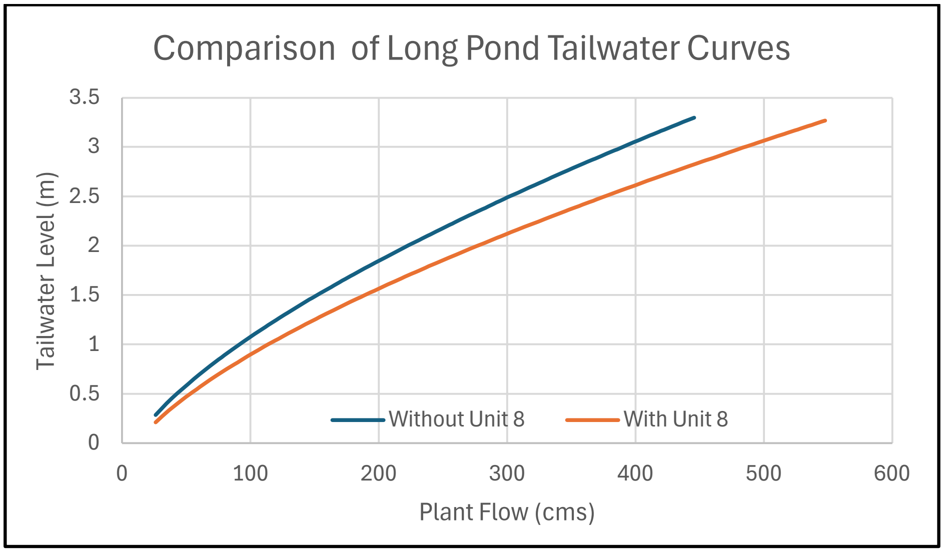

Figure 2-2:Tailwater Curve with and without Unit 8

2.3 Hydrology

Historic inflows for the Bay d'Espoir system are available from 1950. The method used to derive the inflows has changed over time, as the system was developed for hydroelectric power generation. The historic inflows, inflow calculation methods, trends, and inconsistencies in the inflow series were recently reviewed by Hatch (2024). Based on this review, the Bay d'Espoir inflow series were revised, and the revised inflows were used as the basis for this study for Unit 8. The hydrology used by Hatch in the 2020 study was based on an earlier version of the inflow dataset, covering 1950 to 2019. The total inflow upstream of BDE from the 2020 study hydrology and updated hydrology are shown in Figure 2-3, below. It is worth noting that the updated inflows are 3.8% lower than the inflows used in the 2020 study.

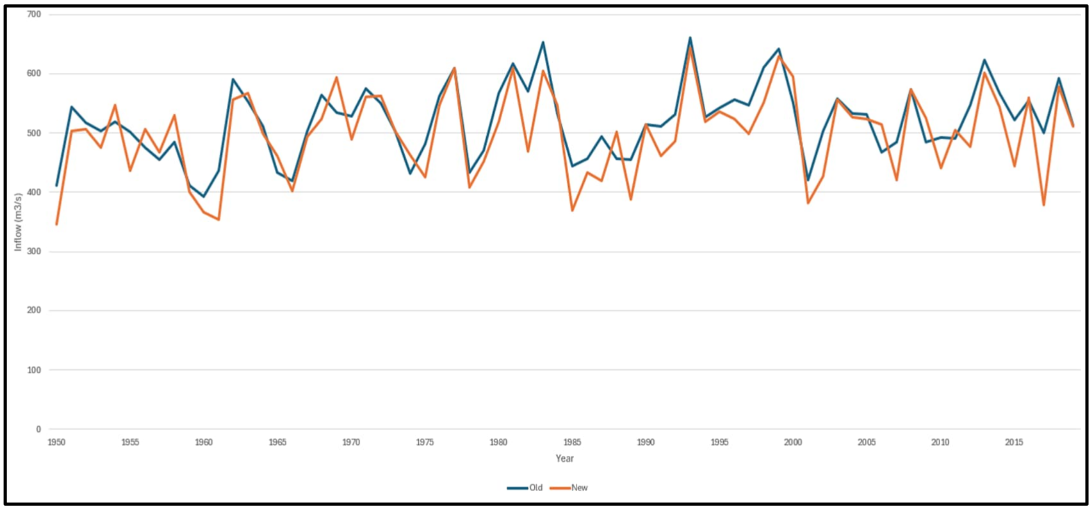

Figure 2-3: BDE Total Inflow Comparison

2.4 Frazil Ice Conditions

The Granite Canal and Upper Salmon plants are susceptible to frazil ice formation. During the winter months, Hydro would try to operate these plants in such a way that a stable ice cover forms on the headponds, and once it is in place these plants can be cycled during the day. However, in recent years winters have been warmer on average making it more difficult to form a stable ice cover. Without an ice cover and if a cold snap occurs, frazil ice formation can severely impact the operations, unless preventative measures are taken, such as reduction in generation.

In the 2020 study, the frazil ice limitation was assessed using operational data for the period 2010 to 2020. For this update, additional data for the period to 2024 was available. The frazil ice periods are summarized in Table 2-1 and Table 2-2.

Table 2-1: Frazil Ice Occurrences at Granite Canal

Year	Nr. Occurrences	Avg. Duration (Hours)	Avg. Generation (MW)
2010	1	14.3	0.0
2011	1	5.4	0.0
2012	1	44.4	0.0
2015	2	16.6	0.0
2018	3	7.2	0.0
2019	2	48.1	10.0
2021	1	106.0	15.0
2022	18	47.9	23.6
2023	11	81.4	27.3
2024	12	61.8	22.5

Table 2-2: Frazil Ice Occurrences at Upper Salmon

Year	Nr. Occurrences	Avg. Duration (Hours)	Avg. Generation (MW)
2010	7	19.7	0.0
2011	1	14.9	0.0
2012	2	6.9	0.0
2013	3	7.6	0.0
2014	5	7.7	0.0
2015	2	6.2	0.0
2016	1	10.4	0.0
2017	1	57.8	0.0
2018	5	17.1	4.0
2019	13	21.3	5.4
2020	3	18.7	33.3
2021	8	16.5	26.4
2022	16	26.2	52.5
2023	4	10.8	60.7
2024	11	39.6	49.6

There is a noticeable increase in occurrences in recent years, and Hydro's response has changed from shutting plants down, to reducing generation during the events. Considering the recent data and in consultation with Hydro, the decision was made to capture the frazil ice effect in this study update, by reducing the maximum generation at Granite Canal and Upper Salmon, for all hours in the December 15th to February 15th period, as follows:

- Granite Canal Plant limited to 56% of capacity.
- Upper Salmon Plant limited to 58.5 % of capacity.

2.5 Load Shape

The daily load shape is one of the Vista inputs for the firm energy analysis. In the 2020 study, the load shape derived from the 2020 Reference Case Load Forecast. For this update to previous study, Hydro provided the 2024 Reference Case load forecast.

2.6 Modelling Approach

Hatch used the same model and approach as in the 2020 study. This includes the proprietary Vista Decision Support System (DSS) model for the study of impacts of Unit 8 on the Bay d'Espoir system. The DSS has been implemented for Hydro assets including the Upper Churchill, Lower Churchill, Exploits River and the integrated Island systems. For this study, the model configuration is limited to the Bay d'Espoir system.

3. Model Analyses

The LT Vista module was used to perform the energy analyses in this study using all the 73 years of provided hydrologic record. LT Vista facilitates studies of long-term assessments and planning using long periods of hydrology.

The model was based on water-balance continuity where flow release decisions are constrained by physical limits and operating rules defined in the setup. The time step as defined in LT Vista is referred to as the period and is specified by the user. Typical period durations are months or weeks but can also be defined as multiples of a day or multiples of a week. The user also defines daily sub-periods within a week, i.e., on-peak, off-peak, shoulder-peak etc., hours for each day in a typical week and there could be as many sub-periods as desired. In model analyses, the average load and price over each period and sub-period are key drivers in the optimization, along with the defined constraints. In this assessment, the Island load profile provided by Hydro varies daily and over each sub-period (within the period). Therefore, the sub-periods should be selected so that derived energy is properly influenced by the provided load profile, i.e., higher generation during higher load sub-periods. The provided Island load for 2024 was analyzed to properly select the sub-periods. The following four sub-periods can be identified from the figure.

- Early hours/late night low load or off-peak period, longer for the weekend than the weekday.
- Morning, mid-day and night high load or shoulder-peak period.
- Morning higher load or peak-period, longer for the weekday than the weekend.
- Evening higher load or peak-period.

It can also be seen that the weekday non-off-peak loads are typically higher than the weekend values. Therefore, eight weekly sub-periods (4 for weekday and 4 weekend) were defined for this study as shown in Figure 3-1.

Hour	Mon	Tue	Wed	Thu	Fri	Sat	Sun
1	1	1	1	1	1	2	2
2	1	1	1	1	1	2	2
3	1	1	1	1	1	2	2
4	1	1	1	1	1	2	2
5	1	1	1	1	1	2	2
6	1	1	1	1	1	2	2
7	3	3	3	3	3	4	4
8	5	5	5	5	5	6	6
9	5	5	5	5	5	6	6
10	5	5	5	5	5	6	6
11	3	3	3	3	3	4	4
12	3	3	3	3	3	4	4
13	3	3	3	3	3	4	4
14	3	3	3	3	3	4	4
15	3	3	3	3	3	4	4
16	3	3	3	3	3	4	4
17	7	7	7	7	7	8	8
18	7	7	7	7	7	8	8
19	7	7	7	7	7	8	8
20	7	7	7	7	7	8	8
21	3	3	3	3	3	4	4
22	3	3	3	3	3	4	4
23	1	1	1	1	1	2	2
24	1	1	1	1	1	2	2

1 (2)	Off-Peak
3 (4)	Shoulder-Peak
5 (6)	Morning-Peak
7 (8)	Evening Peak

Figure 3-1: Modeled Weekly Sub-period Definition

3.1 Firm Energy Analysis

For a hydroelectric system, firm energy is the amount of electricity that can be generated over the most adverse sequence of hydrology, called the critical period. To determine the firm energy, simulations were carried out for the full hydrologic record. LT Vista run time depends on the model time step. The longer the time step, the shorter the run time. The run time increases exponentially as the time step decreases. Therefore, the analysis was carried out in two phases. In phase one, simulation was carried out over the full hydrologic records using a monthly time step to identify the critical period and an initial estimate of the firm energy. In phase two, a more detailed simulation was carried out using a daily time step to more accurately define the firm energy.

3.1.1 Critical Period Analysis

As in the earlier study, LT Vista was run in monthly time step to simulate operations over a 73-year continuous period with a fixed annual load for the existing system with the Upper Salmon bypass. The load shape is defined by the provided 2024 Island load. The annual load gradually increased until the system experienced failure to meet the load. For this analysis, the starting water levels in each reservoir in the system were assumed to be the maximum operating level (MOL) or upper rule curve for each reservoir and time of year, as specified in the Major Reservoir Operations Manual (Hydro, 2015). The total Bay d'Espoir system storage was monitored in order to establish system failure and determine the critical period.

The total system storage trajectories are illustrated in Figure 3-1. As shown in Figure 3-2, the total system storage drops to its minimum level in 1962. The LT simulation indicates that the critical sequence occurs between January 1959 (when system storage was full considering upper rule curves and maximum operating levels of the reservoirs) and March 1962 when the system storage drops to minimum.

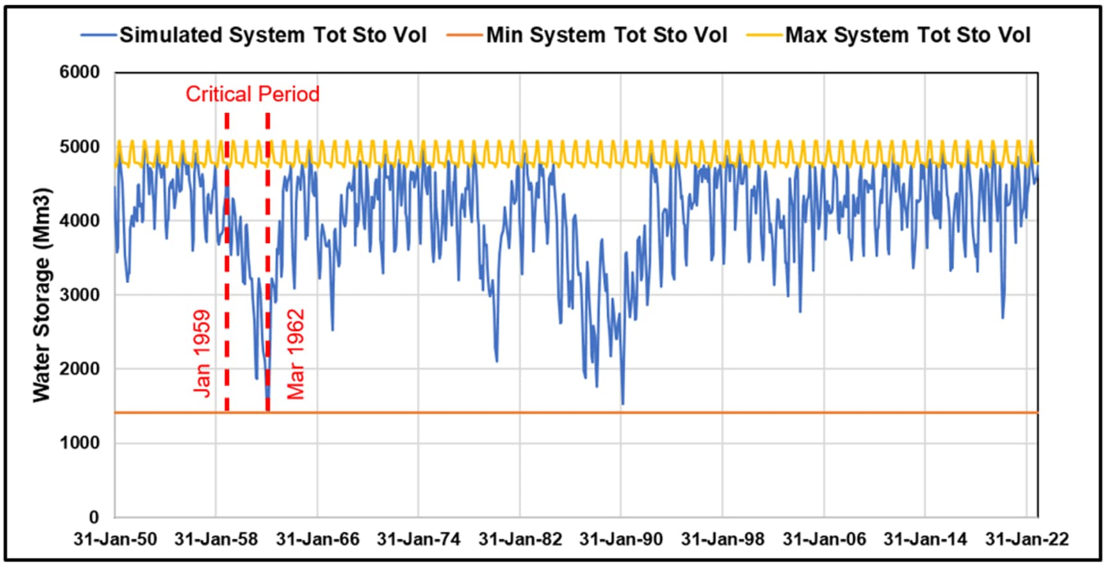

Figure 3-2: System Total Storage Trajectory

3.1.2 Detailed Analysis Using Daily Time Step

Once the critical period had been identified, LT Vista was run from January 1959 to December 1962 using a daily time step for trial annual loads close to 300 MWc. Again, the total system storage was monitored for each load trial to identify the smallest load value that would cause the storage, starting full, to be depleted in the critical period. The detailed analysis was performed for both the existing system with Upper Salmon bypass and the existing system plus Unit 8 and the Upper Salmon bypass.

The shape for each of the load trials is defined by the given 2024 Island load. The final estimate of the firm energy is:

- 294.0 MWc (with peak load of 545 MW) for the existing system and the existing system plus Unit 8.

Figure 3-3 shows the trajectory of the system storage under the existing system firm energy. Both the existing system and the existing system plus Unit 8 annual loads have the same

Figure 3-3 shows the trajectory of the system storage under the existing system firm energy. Both the existing system and the existing system plus Unit 8 annual loads have the same capacity factor of 0.5395 as the 2024 Island load. Figure 3-4 shows a comparison of the existing system's annual firm load with 2024 Island load. As such it can be determined that the addition of Unit 8 does not impact on the firm energy of the Bay d'Espoir plant.

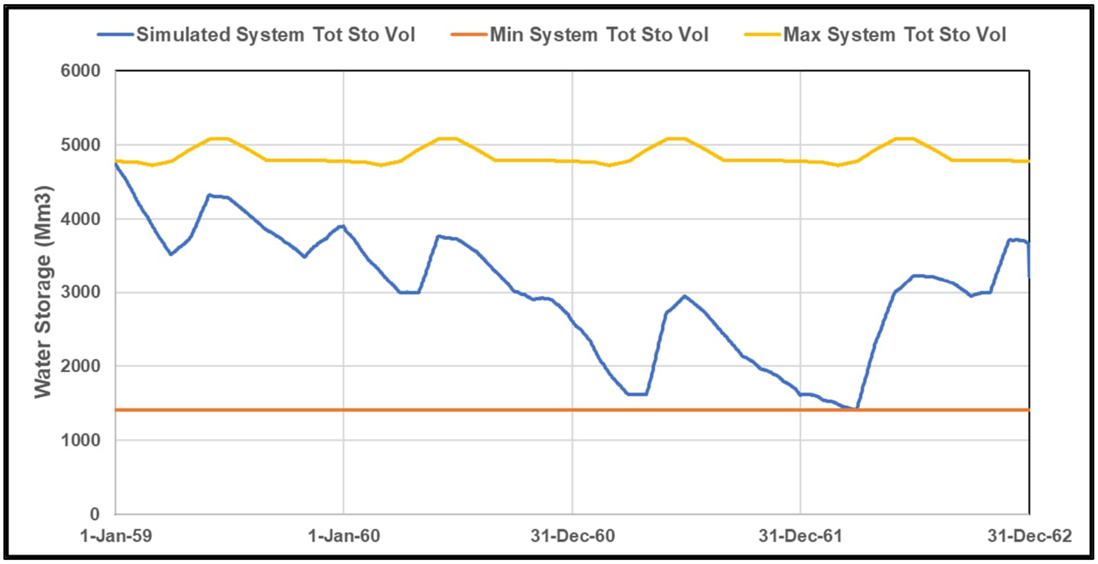

Figure 3-3: Simulated Firm Load System Total Storage Trajectory

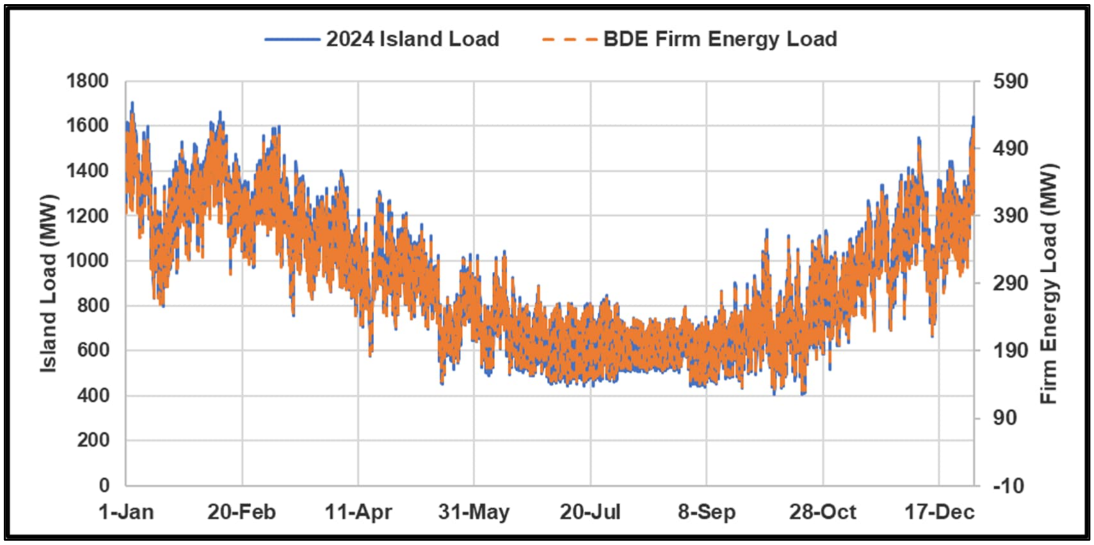

Figure 3-4: Comparison between Hourly 2024 Island Load and Hourly Bay d'Espoir Firm Energy Load

3.2 Energy Capability Analysis

To estimate the energy capability of the Bay d'Espoir system, LT Vista was run to optimize capacity while respecting the firm load requirement. For this purpose, the firm load established in Section 3.1 for the existing system was imposed on the system along with market opportunity to capture secondary energy. In order that the market price reflects the Island system load, and as such the capacity requirement, the hourly market price is set at the hourly load value of the 2024 Island load provided by Hydro.

In order to assess the impact of the potential addition of Bay d'Espoir Unit 8 on the hydroelectric generation and operation of the Bay d'Espoir reservoir system, LT Vista was run for the following four scenarios:

- Existing system with Upper Salmon Bypass.
- Existing system without Upper Salmon Bypass.
- Existing system plus Unit 8, with Upper Salmon Bypass.
- Existing system plus Unit 8, without Upper Salmon Bypass.

All the runs were conducted over the 73-year continuous period of available hydrology.

The results of the energy analysis are presented in Table 3-1 as average annual energy for the Bay d'Espoir system and the contribution from each plant, for each of the four scenarios. The difference and percent difference for the other three scenarios relative to the existing system with Upper Salmon bypass are also presented in the table. The following can be inferred from the table:

- Granite Canal plant average annual energy remains approximately 245 GWh for all four scenarios.
- There is only a very slight reduction in average annual energy for the existing system without Upper Salmon bypass.
- There is a similar level of increase, 0.64 percent, in the system average annual energy with the addition of Unit 8 with the Upper Salmon bypass.
- The average annual energy contributed by the Upper Salmon plant dropped by 2.32 percent and 1.71 percent with addition of Unit 8, with and without Upper Salmon bypass respectively.
- The average annual energy contributed by the Bay d'Espoir plant increased by 1.26 percent and 1.25 percent with addition of Unit 8, with and without Upper Salmon bypass respectively.

Table 3-1: Average Annual Energy for Bay d’Espoir System and the Contributing Plants

Scenario	Total System	Granite Canal Plant	Upper Salmon Plant	Bay d'Espoir Plant
Average Annual Energy (GWh/year)				
Existing System with Upper Salmon Bypass	3359.74	244.81	501.37	2613.56
Existing System without Upper Salmon Bypass	3359.47	244.76	501.21	2613.50
Existing System plus Unit 8, with Upper Salmon Bypass	3381.19	244.97	489.75	2646.46
Existing System plus Unit 8, without Upper Salmon Bypass.	3383.86	244.87	492.78	2646.22
Difference Relative to Existing System with Upper Salmon Bypass (GWh)				
Existing System without Upper Salmon Bypass	-0.28	-0.05	-0.16	-0.07
Existing System plus Unit 8, with Upper Salmon Bypass	21.45	0.17	-11.62	32.90
Existing System plus Unit 8, without Upper Salmon Bypass.	24.12	0.06	-8.59	32.65
Difference Relative to Existing System with Upper Salmon Bypass (%)				
Existing System without Upper Salmon Bypass	-0.01%	-0.02%	-0.03%	0.00%
Existing System plus Unit 8, with Upper Salmon Bypass	0.64%	0.07%	-2.32%	1.26%
Existing System plus Unit 8, without Upper Salmon Bypass.	0.72%	0.03%	-1.71%	1.25%

3.3 Detailed Model Results

Detailed model results are presented in the following subsections as tables, duration curves and monthly box plots. The centered-vertical line of the box plots extends from the minimum value to the maximum value. The horizontal line in the box is the median and the lower and upper ends of the box represents the 25th percentile and 75th percentile respectively. Where tables are presented for off-peak and on-peak values, the on-peak hours are hours 7 to 22 each day of the week, and the off-peak hours are hours 1 to 6, 23 and 24 each day of the week.

3.3.1 Firm Energy

Firm annual energy of the existing system and the existing system plus Unit 8 was estimated as 294.0 MWc. The system annual firm energy of the existing system of 294.0 MWc (2,543.66 GWh) is therefore adopted for the system. The corresponding annual firm energy for the Bay d’Espoir plant is 2,234.50 GWh. The corresponding total, on-peak and off-peak firm monthly energy for the system along with contributions from each plant are presented in Table 3-2.

Table 3-2: Firm Monthly Energy (GWh) for Bay d'Espoir System and the Contributing Plants

Month	Total	On-Peak	Off-Peak	Total	On-Peak	Off-Peak
	System			**Granite Canal Plant**		
January	268.96	81.68	187.27	15.22	4.97	10.25
February	277.13	85.36	191.77	15.43	4.93	10.50
March	267.23	81.72	185.51	17.99	5.10	12.89
April	221.47	66.20	155.27	19.63	6.10	13.53
May	188.30	56.55	131.76	28.40	9.54	18.86
June	159.20	46.03	113.17	15.71	5.69	10.01
July	151.94	43.34	108.60	13.22	6.24	6.98
August	149.62	44.30	105.32	13.43	5.42	8.01
September	154.10	44.06	110.04	15.82	6.20	9.62
October	181.93	50.64	131.30	18.85	6.74	12.12
November	235.39	68.73	166.66	20.80	6.88	13.92
December	288.40	85.42	202.97	17.38	5.92	11.46
	Upper Salmon Plant			**Bay d'Espoir Plant**		
January	19.01	6.51	12.50	234.73	70.20	164.52
February	22.81	7.90	14.91	238.89	72.53	166.36
March	24.40	8.24	16.17	224.83	68.38	156.45
April	9.29	4.47	4.82	192.55	55.64	136.92
May	7.32	3.31	4.01	152.58	43.69	108.89
June	2.95	1.27	1.67	140.55	39.06	101.48
July	0.75	0.16	0.60	137.96	36.94	101.02
August	0.59	0.10	0.49	135.59	38.78	96.81
September	0.50	0.19	0.31	137.78	37.66	100.11
October	0.80	0.28	0.52	162.28	43.62	118.66
November	3.67	1.74	1.94	210.91	60.11	150.80
December	5.17	1.45	3.73	265.85	78.06	187.79

3.3.2 Average Monthly Energy

The average annual energy for each scenario was presented in Table 3-1. The total, on-peak and off-peak average monthly energy for the system along with contributions from each plant, are presented in Table 3-3 to Table 3-6. It will be noted that there is a general increase in the on-peak generation and decrease in off-peak generation for the river system and Bay d'Espoir plant with addition of Unit 8. The monthly on-peak and off-peak generation at Granite Canal and Upper Salmon plants remain essentially the same with addition of Bay d'Espoir Unit 8. This change in distribution of generation at Bay d'Espoir plant is discussed further in Section 3.3.3 below.

Table 3-3: Average Monthly Energy (GWh) for Bay d'Espoir System

Month	Total	On-Peak	Off-Peak	Total	On-Peak	Off-Peak
	Existing System With Upper Salmon Bypass			**Existing System Without Upper Salmon Bypass**		
January	397.92	288.32	109.60	393.52	285.56	107.96
February	407.35	286.80	120.56	404.16	285.38	118.79
March	390.32	293.14	97.19	388.05	291.95	96.10
April	330.52	259.17	71.35	331.85	259.95	71.90
May	243.15	184.53	58.61	245.32	185.92	59.40
June	171.07	126.57	44.50	173.43	128.90	44.53
July	154.99	113.09	41.90	154.98	113.23	41.75
August	149.92	106.91	43.01	150.34	107.34	43.01
September	163.89	121.37	42.52	165.20	122.68	42.51
October	231.53	182.75	48.78	232.52	183.81	48.71
November	338.08	263.51	74.57	338.82	263.88	74.93
December	381.00	280.70	100.30	381.28	280.88	100.40
	Existing System Plus Unit 8, With Upper Salmon Bypass			**Existing System Plus Unit 8, Without Upper Salmon Bypass**		
January	413.62	312.50	101.12	403.06	305.48	97.58
February	449.69	327.22	122.47	441.98	323.07	118.91
March	387.51	299.29	88.22	383.67	296.86	86.81
April	327.51	261.39	66.12	332.23	265.44	66.79
May	229.87	172.98	56.89	236.28	178.70	57.58
June	163.24	118.80	44.45	167.40	122.92	44.48
July	153.71	111.95	41.77	153.62	111.86	41.76
August	149.60	106.59	43.01	149.72	106.71	43.01
September	158.10	115.60	42.50	161.31	118.80	42.51
October	220.29	171.65	48.64	224.01	175.34	48.66
November	337.72	267.72	70.00	339.25	269.17	70.08
December	390.31	291.31	99.00	391.33	292.31	99.02

Table 3-4: Average Monthly Energy (GWh) for Granite Canal Generating Station

Month	Total	On-Peak	Off-Peak	Total	On-Peak	Off-Peak
	Existing System With Upper Salmon Bypass			**Existing System Without Upper Salmon Bypass**		
January	17.40	11.82	5.58	17.40	11.82	5.58
February	20.95	14.18	6.76	20.96	14.18	6.78
March	27.56	19.26	8.30	27.66	19.31	8.34
April	24.06	17.37	6.69	24.05	17.36	6.70
May	25.04	18.24	6.80	25.09	18.31	6.79
June	17.49	14.47	3.02	17.58	14.58	3.00
July	15.60	11.30	4.30	15.33	11.46	3.87
August	14.80	10.32	4.48	14.80	10.34	4.46
September	15.61	11.21	4.40	15.56	11.42	4.14
October	20.56	14.55	6.01	20.65	14.72	5.93
November	24.54	17.44	7.10	24.46	17.47	7.00
December	21.20	14.89	6.31	21.21	14.89	6.31
	Existing System Plus Unit 8, With Upper Salmon Bypass			**Existing System Plus Unit 8, Without Upper Salmon Bypass**		
January	17.43	11.82	5.61	17.42	11.82	5.60
February	21.00	14.18	6.82	21.00	14.18	6.82
March	27.49	19.07	8.42	27.48	19.09	8.39
April	23.92	17.02	6.90	24.04	17.13	6.91
May	25.16	18.13	7.03	25.18	18.17	7.02
June	18.05	14.53	3.52	18.15	14.72	3.43
July	16.18	11.09	5.08	16.05	11.64	4.41
August	14.92	9.74	5.17	14.65	10.00	4.65
September	15.50	11.04	4.45	15.17	11.10	4.07
October	19.99	13.89	6.10	20.39	14.37	6.01
November	24.22	17.07	7.15	24.27	17.16	7.11
December	21.12	14.74	6.38	21.08	14.76	6.31

Table 3-5: Average Monthly Energy (GWh) for Upper Salmon Generating Station

Month	Total	On-Peak	Off-Peak	Total	On-Peak	Off-Peak
	Existing System With Upper Salmon Bypass			**Existing System Without Upper Salmon Bypass**		
January	34.83	23.22	11.61	33.68	22.50	11.17
February	43.07	28.71	14.35	42.44	28.29	14.15
March	61.33	40.93	20.40	61.22	40.81	20.41
April	57.10	38.33	18.77	57.03	38.34	18.69
May	53.63	37.09	16.53	53.27	36.69	16.57
June	42.72	30.42	12.31	42.91	30.52	12.39
July	28.55	22.92	5.63	29.35	22.69	6.66
August	20.53	15.99	4.54	21.32	16.57	4.75
September	23.55	19.42	4.13	24.11	18.88	5.23
October	36.61	28.57	8.04	36.54	28.08	8.47
November	53.13	36.57	16.56	53.16	36.41	16.76
December	46.32	30.96	15.36	46.20	30.88	15.32
	Existing System Plus Unit 8, With Upper Salmon Bypass			**Existing System Plus Unit 8, Without Upper Salmon Bypass**		
January	34.83	23.22	11.61	33.68	22.48	11.20
February	43.07	28.72	14.35	42.37	28.28	14.09
March	61.36	40.95	20.41	61.13	40.82	20.30
April	56.63	38.00	18.63	56.79	38.08	18.70
May	52.81	36.50	16.31	53.11	36.55	16.57
June	41.33	29.69	11.64	41.77	29.63	12.14
July	25.57	21.06	4.51	27.14	21.21	5.93
August	19.22	14.78	4.43	20.41	14.88	5.53
September	22.55	18.16	4.38	23.49	18.26	5.22
October	33.60	25.70	7.90	34.49	25.91	8.57
November	52.39	35.97	16.42	52.19	35.61	16.57
December	46.40	30.96	15.44	46.21	30.85	15.37

Table 3-6: Average Monthly Energy (GWh) for Bay d'Espoir Generating Station

Month	Total	On-Peak	Off-Peak	Total	On-Peak	Off-Peak
	Existing System With Upper Salmon Bypass			**Existing System Without Upper Salmon Bypass**		
January	345.68	253.27	92.40	342.44	251.24	91.20
February	343.34	243.90	99.44	340.76	242.91	97.86
March	301.43	232.94	68.49	299.18	231.83	67.35
April	249.36	203.47	45.89	250.77	204.25	46.52
May	164.48	129.20	35.28	166.96	130.92	36.04
June	110.86	81.69	29.18	112.94	83.80	29.14
July	110.84	78.87	31.97	110.30	79.08	31.22
August	114.59	80.60	33.99	114.23	80.43	33.80
September	124.73	90.74	33.99	125.52	92.38	33.14
October	174.36	139.63	34.73	175.33	141.02	34.31
November	260.41	209.50	50.91	261.19	210.01	51.18
December	313.49	234.85	78.63	313.88	235.10	78.77
	Existing System Plus Unit 8, With Upper Salmon Bypass			**Existing System Plus Unit 8, Without Upper Salmon Bypass**		
January	361.36	277.46	83.90	351.96	271.18	80.78
February	385.62	284.32	101.30	378.60	280.61	97.99
March	298.66	239.28	59.38	295.06	236.95	58.12
April	246.96	206.37	40.59	251.40	210.23	41.17
May	151.90	118.35	33.55	157.98	123.99	33.99
June	103.87	74.58	29.29	107.48	78.57	28.91
July	111.97	79.79	32.18	110.43	79.02	31.42
August	115.47	82.07	33.40	114.66	81.83	32.83
September	120.06	86.39	33.67	122.66	89.44	33.22
October	166.70	132.06	34.64	169.14	135.06	34.08
November	261.11	214.68	46.43	262.80	216.40	46.40
December	322.78	245.60	77.18	324.05	246.70	77.34

3.3.3 *Impact on Distribution of Generation at Bay d'Espoir Generating Station*

Figure 3-5 shows a comparison of the monthly box plot of the hourly generation at Bay d'Espoir plant. The following can be inferred from the figure:

- The optimized maximum hourly generation increased from near 600 MW for the existing plant to well over 700 MW, with the addition of Unit 8, in the fall to spring months of October to May.
- There is a significant increase in optimized maximum generation in June and September with the addition of Unit 8.

- There is a reduction in optimized maximum generation in July and August, with addition of Unit 8, an indication that energy is moved from these low load months to high load months.
- The 25th to 75th percentile spread in the winter months of December to March is much wider with the addition of Unit 8, an indication of significant energy movement from off-peak period to on-peak period in these high load months.

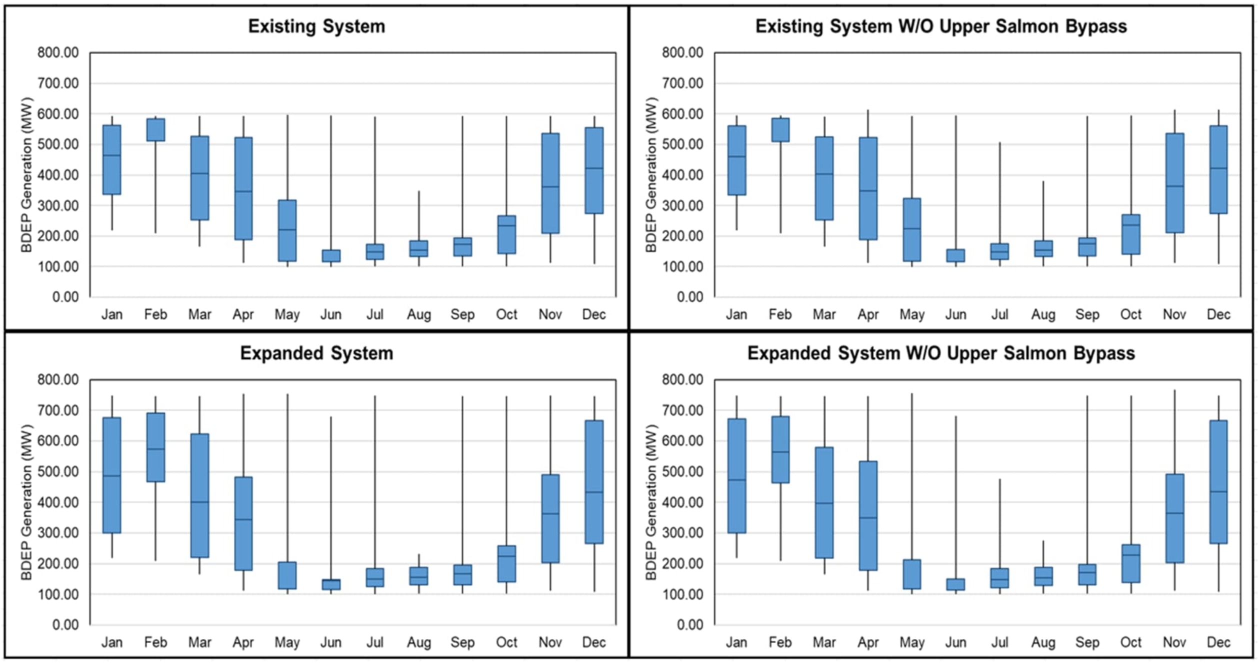

Figure 3-5: Variation in Hourly Bay d'Espoir Plant Generation by Month

Figure 3-6 shows a comparison of the hourly generation duration curves of the four scenarios. The curves for existing system with and without Upper Salmon bypass are identical. Similarly, the curves for existing system plus Unit 8 with and without Upper Salmon bypass are identical. The figure has the following distinct segments.

- A segment representing 18.6 percent of the time when generation with addition of Unit 8 is higher than that of the existing system. These are typically on-peak hours.
- A second segment representing 27.9 percent of the time when generation with addition of Unit 8 is lower than that of the existing system. These are off-peak hours from which energy is moved to the on-peak hours.

- A third segment representing 53.5 percent of the time when generation with the existing and system and the expanded systems are identical. These are hours when the committed firm load is just met.

The optimized maximum generation for the existing Bay d'Espoir plant is 597.3 MW which increased to 747.4 MW with addition of Unit 8. This is an optimized increase of 150.1 MW during some of the on-peak hours. It is less than the 154.4 MW capacity of Unit 8 because the gain in on-peak hour generation is at the expense of off-peak hour generation during which firm load must also be met. To increase on-peak hour generation to 154.4 MW will compromise meeting of firm load in some off-peak hours which will then have to be met from other resources.

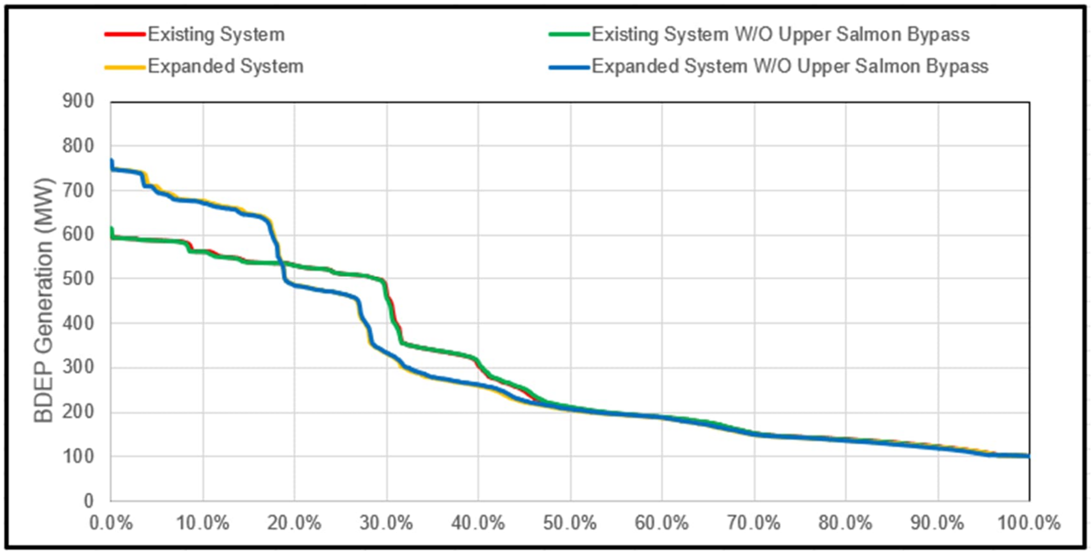

Figure 3-6: Duration Curves of Hourly Bay d'Espoir Plant Generation

The model does indeed employ Unit 8 at its full 154.4 MW capacity, being the first unit in scheduling order (discussed in the 2020 study). However, the model optimizes the total Bay d'Espoir plant output, with the objectives of meeting the defined firm every hour and maximizing average energy. Output at full rated capacity of the plant is possible, but there would be a tradeoff with reduced firm and average simulated energy. Likewise, increased duration of output in the high range (e.g., 700+ MW) is also possible, but with the tradeoff of reduced firm and average simulated energy. This condition is a result of the Bay d'Espoir system being modelled in isolation for the purposes of this analysis. Through optimization of Hydro's full hydraulic resources, which was not simulated as part of this study, resources can likely be managed to fully mitigate the potential for energy shortfall from the Bay d'Espoir system to achieve an optimized increase in maximum generation equal to the full unit capability of 154.4 MW. Hydro's intent is not to generate more from the Bay d'Espoir plant on an energy basis, but rather to shift generation from the off-peak hours and non-winter period to the on-peak hours and winter period (i.e., Labrador-Island Link deliveries and/or other on-island generation can be used to replenish the Bay d'Espoir system during the off-peak periods).

The information provided by Hydro on the hydromechanical equipment, head losses and tailwater do not indicate any physical restrictions to prevent Unit 8 from attaining 154.4 MW, or the Bay d'Espoir plant from attaining its full rated capacity, if there is water in the reservoir.

3.3.4 Impact on Efficiency of Bay d'Espoir Generating Station

The efficiency curve used for Unit 8 is the same as in earlier study and there is no change on BDE plant efficiency from earlier study.

3.3.5 Upper Salmon Bypass and West Salmon Spillway Usage

The Upper Salmon bypass (i.e., North Salmon spillway) is used to pass flows from the Upper Salmon reservoir to Long Pond while bypassing the Upper Salmon plant. According to Hydro, reasons for this may include periods of high inflow that exceed the capacity flow at the Upper Salmon plant and cannot be stored; periods when the Upper Salmon plant is shut down; and when necessary to delay water from reaching the Long Pong reservoir to provide more time to generate water out of the Long Pond reservoir when the Long Pond water level is high.

It was shown in Figure 3-6 that the duration curve of the Bay d'Espoir hourly generation is identical with or without Upper Salmon bypass. This suggests that the bypass is rarely needed to maintain peaking at the plant. So, it is desirable to examine the usage of the bypass and West Salmon spillway.

Figure 3-7 shows duration curves of hourly flows in the North Salmon Spillway and Figure 3-8 shows the duration curves of hourly flows in the West Salmon spillway. The North Salmon spillway is used 2.5 percent and 3.0 percent of the time for the existing and expanded systems respectively. West Salmon spillway is used only 0.2 percent of the time for both the existing and expanded systems when the North Salmon spillway is available. The spillway is used 10.1 percent and 11.8 percent of the time for the existing and expanded systems respectively without the bypass in the system. There are no spills at Long Pond in any of the scenarios as the capacity driven requirement for generation from Bay d'Espoir is higher than the capacity flow at the Upper Salmon plant.

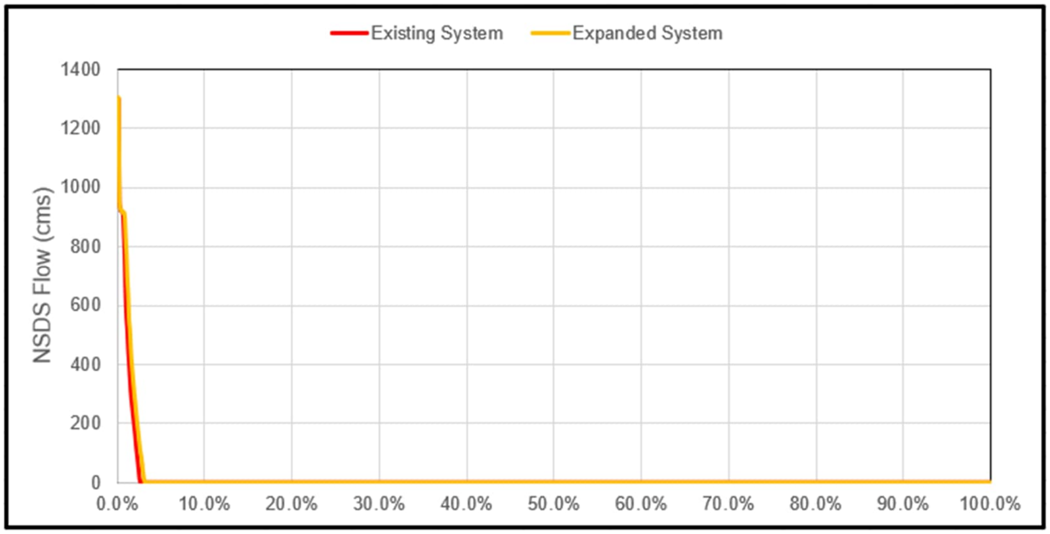

Figure 3-7: Duration Curves of Hourly Flows in the North Salmon Spillway

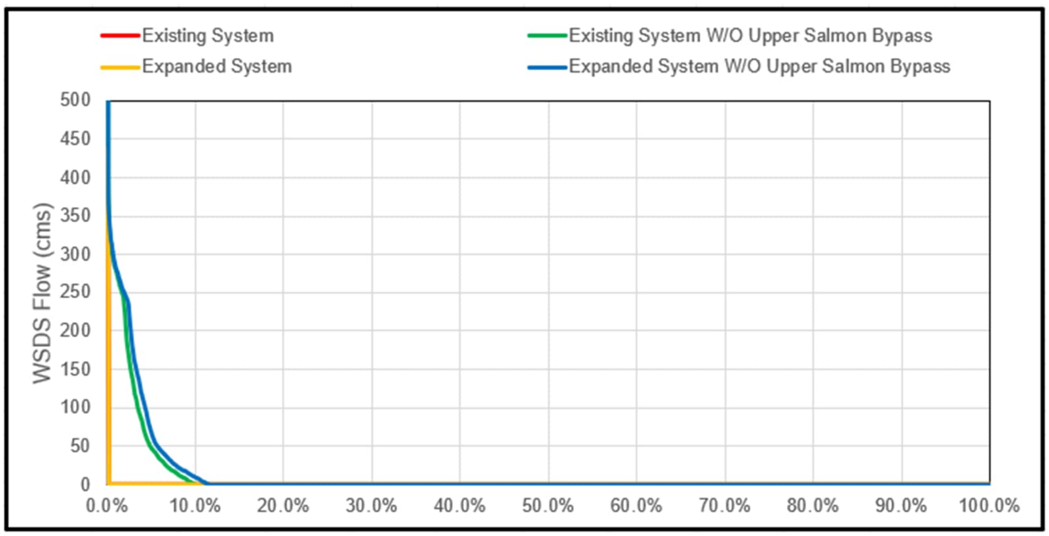

Figure 3-8: Duration Curves of Hourly Flows in the West Salmon Spillway

3.3.6 Impact on the Operation of Upper Salmon Hydroelectric Generating Station

Figure 3-9 shows the monthly box plot of the power flow at Upper Salmon. The impact on generation is very subtle and there are slight noticeable differences between the existing and expanded systems operation only in the high load months of January to March. Operations in the rest of the year are quite identical. Comparing the existing and expanded case with the bypass and focusing on the boxes in the box plot, power flows for the expanded case are slightly higher in January to March. In cases without the bypass, power flows are also higher in the expanded system than the existing system in January to March.

Figure 3-10 shows the duration curves of the hourly generation efficiency at the plant. It can be seen in the figure that, as a result of the January to March increased power flow in the expanded system, the plant is operated slightly less often, 80.8 percent of the time in the expanded system compared to 82.6 percent of the time in the existing system. There is also a loss of efficiency about 3.6 percent of the time in the expanded system compared to the existing system.

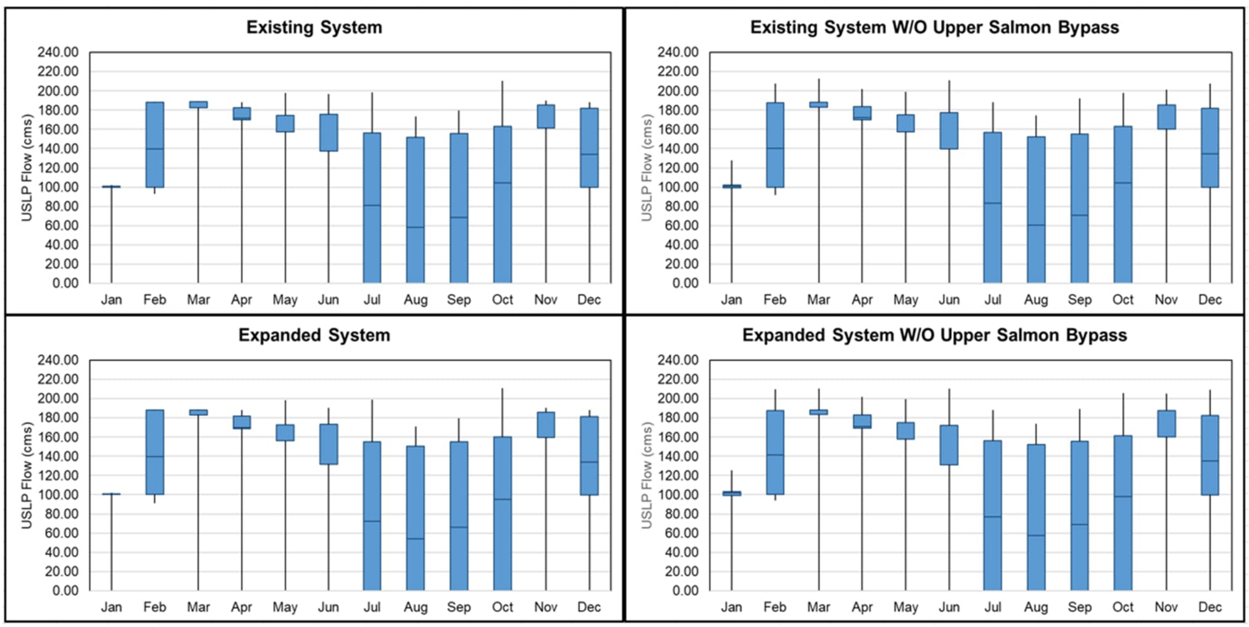

Figure 3-9: Variation in Hourly Upper Salmon Generation Flow by Month

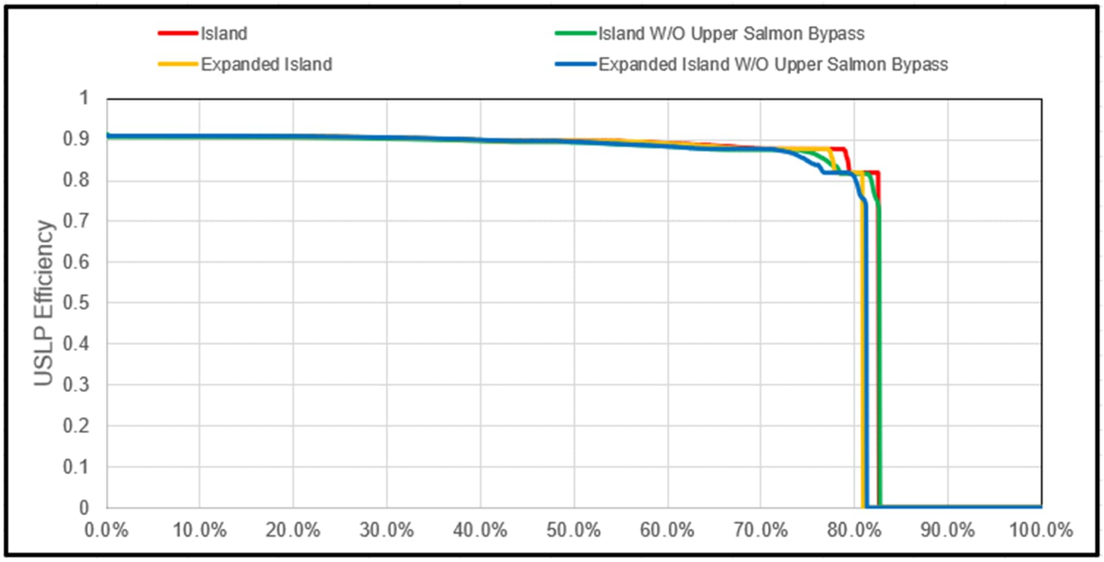

Figure 3-10: Duration Curves of Hourly Generation Efficiency at Upper Salmon Plant

3.3.7 Recommended Range of Storage of the Bay d’Espoir System Reservoirs in Advance of Winter Operating Season

The range of simulated monthly end elevations of the three large reservoirs are presented in the following sections. The optimization analysis in this study is for the Bay d’Espoir system alone. Therefore, these elevation ranges are those that maximize the economic benefits of the Bay d’Espoir system generation and not necessarily the overall Hydro generation system. With this recognition, ranges of end-of-November storage for each reservoir are recommended in this section, to maximize generation in the winter months and allow room for possible early winter high flow. If levels at the end of November are lower than the recommended ranges, the system may not be able to achieve as much peaking in winter. If reservoir levels at the end of November are lower than the recommended ranges, it is likely that energy can be sourced, such as from the LIL, to support reservoir storage.

3.3.7.1 Victoria Reservoir

Figure 3-11 shows the variation in monthly end elevation of Victoria Reservoir. The elevation ranges and variations are identical across all scenarios. An elevation range of 323.59 m to 325.39 m representing the 25th to the 75th percentiles is recommended at the end of November for Victoria Reservoir.

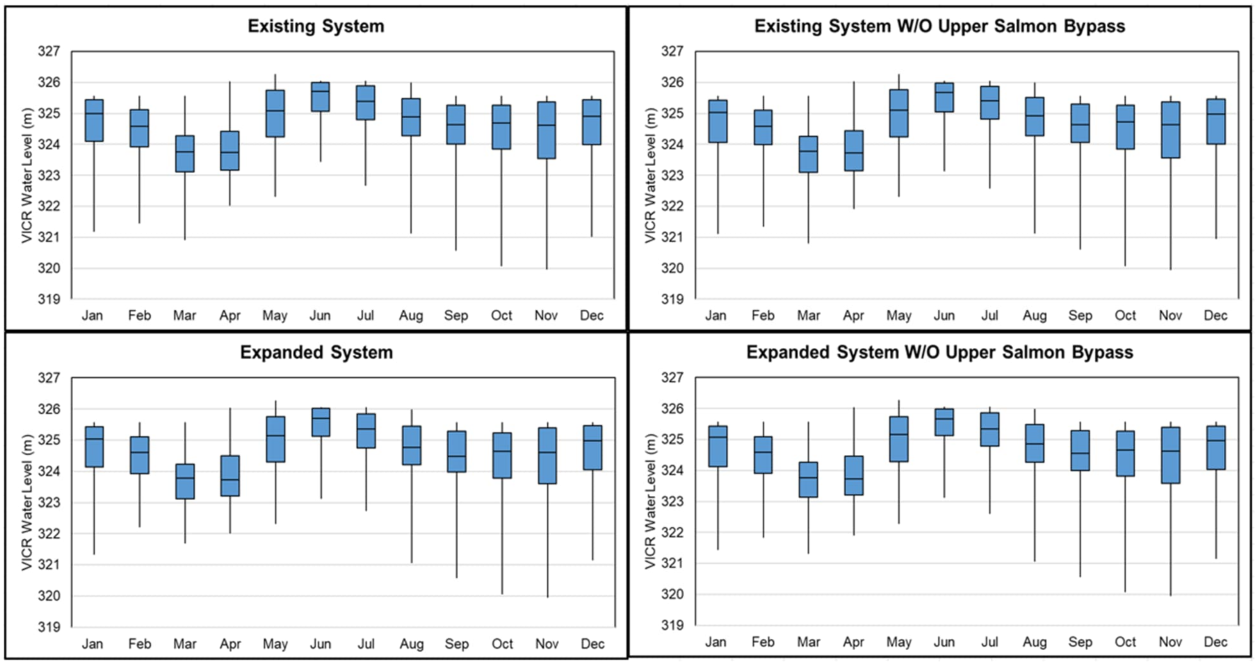

Figure 3-11: Variation in Victoria Reservoir Monthly End Elevation

3.3.7.2 Meelpaeg Reservoir

Figure 3-12 shows the variation in monthly end elevation of Meelpaeg Reservoir. The variation is different in the winter months of January to May for the expanded system. In these months, the 25th to 75th percentiles are both wider and lower for the expanded system than for the existing system. The minimum elevations for the expanded system are also lower in these months. However, the variation and range of elevations in November are identical across all scenarios. An elevation range of 271.72 m to 272.18 m representing the 25th to the 75th percentiles is recommended at the end of November for Meelpaeg Reservoir.

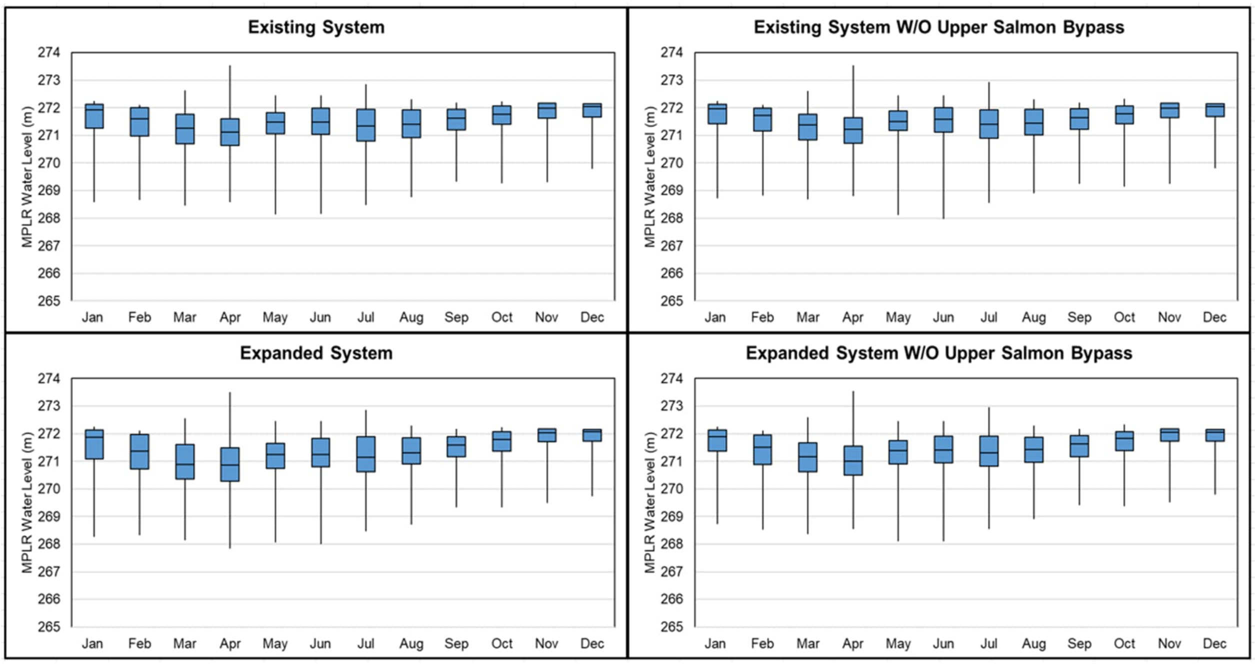

Figure 3-12: Variation in Meelpaeg Reservoir Monthly End Elevation

3.3.7.3 Long Pond Reservoir

Figure 3-13 shows the variation in monthly end elevation of Long Pond Reservoir. The elevation ranges and variations are identical across all scenarios from December to May with some differences in the remaining months of the year. The November elevation range is tight. This month has the highest minimum month end elevation in each of the scenarios to provide storage for optimum generation through winter. Therefore, an elevation range of 182.22 m to 182.25 m is recommended at the end of November for the Long Pond Reservoir. 182.22 m is the minimum end of November elevation of the four scenarios and 182.25 m is the 75th percentile of the November end elevation across all scenarios.

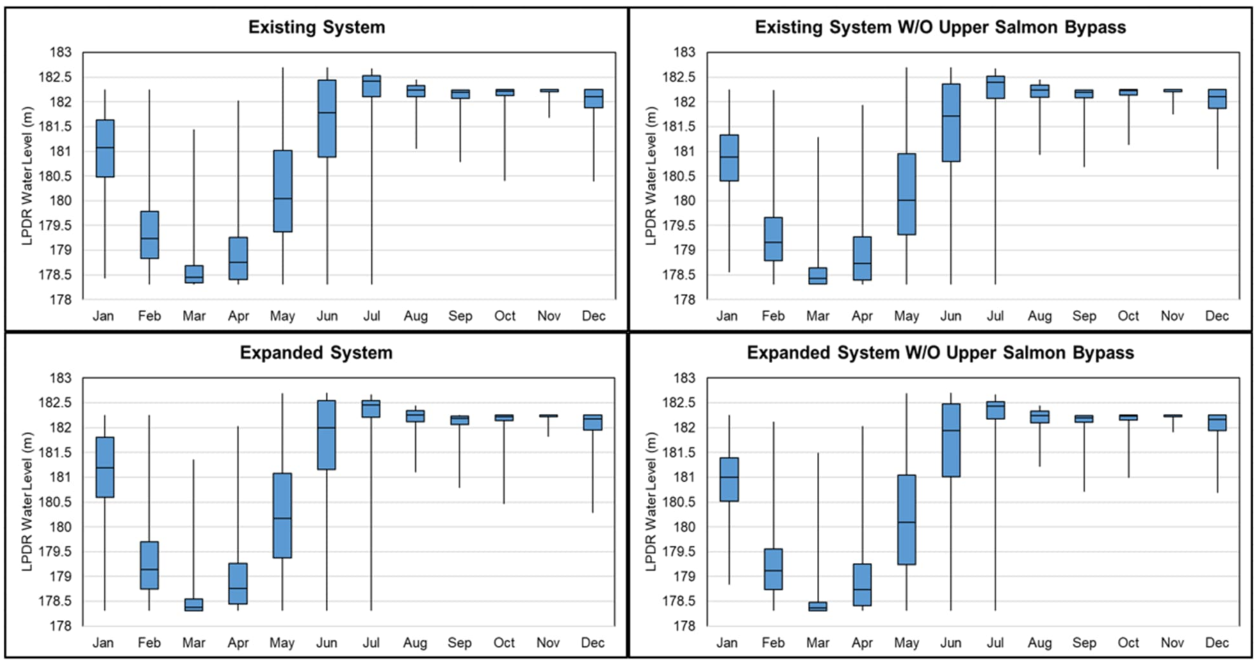

Figure 3-13: Variation in Long Pond Reservoir Monthly End Elevation

4. Conclusions

4.1 Conclusions

The conclusions of the update are as follows.

1. This update study confirms the results of the earlier study.
2. The firm energy estimate for the Bay d'Espoir system with Unit 8 is 294 MWc, down from the earlier estimate of 297.5 MWc. This reduction is attributed to the revised historic inflows and updated load forecast.
3. The simulated average annual energy of the existing Bay d'Espoir system is 3,359.74 GWh. With the addition of Unit 8, it increases to 3,381.19 GWh, due to higher efficiency of the new unit and some spill capture.
4. The simulated average annual energy of the Bay d'Espoir plant is 2,613.56 GWh. The simulated average annual energy of the plant with the addition of Unit 8 is 2,646.46 GWh, an increase of 1.26 percent.
5. With the addition of Unit 8, the simulated hourly generation of the Bay d'Espoir plant increases 18.6 percent of the time and decreases 27.9 percent of the time. The increased generation occurs during on-peak hours while the decreased generation occurs during off-peak hours.
6. The study also confirmed the optimum utilization of the new unit. It will be the most efficient unit in the plant and should be base loaded.
7. The simulated hourly optimized generation capacity increase at the Bay d'Espoir plant is 150.1 MW with addition of Unit 8. This is less than the 154.4 MW capacity of the new unit because, although the model utilizes the full capacity of Unit 8, it optimizes the total Bay d'Espoir plant output to meet the defined firm load while maximizing energy. The increase in simulated on-peak generation is at the expense of simulated off-peak generation. This condition is a result of the Bay d'Espoir system being modelled in isolation for the purposes of this analysis. Through optimization of Hydro's full hydraulic resources, which was not simulated as part of this study, resources can likely be managed to fully mitigate the potential for energy shortfall from the Bay d'Espoir system to achieve an optimized increase in maximum generation equal to the full unit capability of 154.4 MW.
8. With addition of Unit 8, simulated Bay d'Espoir plant efficiency increases are in the range of 0.16 to 1.83 percent, with an average of 0.76 percent.
9. The North Salmon bypass spillway is used only 2.5 percent of the time in the simulation of the existing system, and 3.0 percent of the time with addition of Unit 8. The bypass may be used during periods of high inflow that exceed the capacity flow at the Upper Salmon plant and cannot be stored; periods when the Upper Salmon plant is shut down;

and when necessary to delay water from reaching the Long Pong reservoir to provide more time to generate water out of the Long Pond reservoir when the Long Pond water level is high.

10. There is a slight loss of simulated efficiency at Upper Salmon plant with addition of Bay d'Espoir Unit 8. This loss occurred 17.98 percent of the time.
11. The information provided by Hydro on the hydromechanical equipment, head losses and tailwater does not indicate any physical restrictions to prevent Unit 8 from attaining 154.4 MW, or the Bay d'Espoir plant from attaining its full rated capacity, as long as there is water in the reservoir.
12. This study also re-examined the end-of-November elevation ranges and reconfirmed the range from the earlier study, that is, the large storage reservoirs in the system to optimize Bay d'Espoir system generation in the winter months while allowing room for possible early winter high flow.
    - Victoria: 323.59 m to 325.39 m
    - Meelpaeg: 271.72 m to 272.18 m
    - Long Pond: 182.22 m to 182.25 m.

    If levels at the end of November are lower than the recommended ranges, the system may not be able to do as much peaking in winter.

5. References

Hatch (2020). Hydrology and Feasibility Study for Potential Bay d'Espoir Hydroelectric Generating Unit No. 8. H363582-00000-228-230-0001, Rev. 0, December 11, 2020.

Hatch (2024). 2023 Hydrology Review. H372150-0000-2B0-230-0001, Rev. B. Prepared for Newfoundland and Labrador Hydro, April 5, 2024.

Newfoundland and Labrador Hydro (2015). Major Reservoir Operation Manual. Revision 5, January 2015.

SNC-Lavalin Inc. (SLI) (2018a). Proposed Bay d'Espoir Hydro Generating Unit 8 – Class 3 Cost Estimate and Project Execution Schedule. 647756-0000-40ER-I-0002-00. Prepared for Newfoundland and Labrador Hydro, March 22, 2018.

SNC-Lavalin Inc. (SLI) (2018b). Proposed Bay d'Espoir Hydro Generating Unit 8 – Hydraulic Analysis of the Conveyance System. 647756-0000-40ER-I-0001-00. Prepared for Newfoundland and Labrador Hydro, March 22, 2018.

Schedule 2

Settlement Agreement

IN THE MATTER OF the *Electrical Power Control Act, 1994*, SNL 1994, Chapter E-5.1 ("*EPCA*") and the *Public Utilities Act*, RSN 1990, Chapter P-47 ("*Act*");

AND IN THE MATTER OF the Reliability and Resource Adequacy Study Review ("RRA Study Review") and the 2024 Resource Adequacy Plan dated July 9, 2024, and Revision 1 dated July 11, 2024 and Revision 2 dated August 26, 2024, filed by Newfoundland and Labrador Hydro.

SETTLEMENT AGREEMENT

WHEREAS Newfoundland and Labrador Hydro ("Hydro") filed its initial Reliability and Resource Adequacy Study with the Board of Commissioners of Public Utilities ("Board") in November 2018, with updates of that study filed in 2019, 2020, 2021 and 2022, and a 2024 Resource Adequacy Plan filed in November 2024; and

WHEREAS the ongoing RRA Study Review is intended to address Hydro's long-term approach to providing continued reliable service for its customers, and the 2024 Resource Adequacy Plan provides an in-depth analysis of the amount of electricity customers will need over the next ten years, identifies system requirements, and recommends a minimum investment required expansion plan to ensure the continued reliability of the Island Interconnected System;

WHEREAS the participants in the review are the Consumer Advocate; Newfoundland Power Inc. ("Newfoundland Power"); Corner Brook Pulp and Paper Limited, NARL Refining LP and Vale Newfoundland and Labrador Limited (the "IIC Group"), and the Labrador Interconnected Group, which consists of the Sheshatshiu Innu First Nation and the Towns of Happy Valley-Goose Bay, Wabush, and Labrador City; and

WHEREAS the Consumer Advocate, Newfoundland Power, the IIC Group, and the Labrador Interconnected Group have issued and Hydro has answered Requests for Information regarding the filings in the RRA Study Review including the 2024 Resource Adequacy Plan and has attended numerous technical conferences and other briefings; and

WHEREAS Hydro, the Consumer Advocate, Newfoundland Power, the IIC Group, with participation by Board Hearing Counsel, have engaged in negotiations regarding Hydro's 2024 Resource Adequacy Plan and its specific application to the Island Interconnected System;

TERMS OF AGREEMENT

1. Hydro, the Consumer Advocate, Newfoundland Power, the IIC Group, and the Labrador Interconnected Group, have agreed that planning for the Island and Labrador should continue to be completed separately.

2. Hydro, the Consumer Advocate, Newfoundland Power, and the IIC Group jointly advise the Board that various issues arising regarding the RRA Study Review and the 2024 Resource Adequacy Plan have been settled by negotiations between them in accordance with this

Settlement Agreement, which issues are detailed in Attachment 1 to this Settlement Agreement (the "Settled Issues").

3. Hydro, the Consumer Advocate, Newfoundland Power, and the IIC Group recommend that the Board accept the agreement of the Consumer Advocate, Newfoundland Power, and the IIC Group regarding the Settled Issues during the Board's evaluation of Hydro's application to construct a new 154 MW unit at Bay d'Espoir and a 150 MW combustion turbine on the Avalon Peninsula and any applications related thereto.

4. Hydro, the Consumer Advocate, Newfoundland Power, and the IIC Group consent to the admission in the record of matter of all pre-filed testimony, exhibits and responses to requests for information pertaining to the Settled Issues.

5. At any hearing pertaining to any proceeding filed to implement the 2024 Resource Adequacy Plan recommendations to proceed with the addition of Bay d'Espoir Unit 8 and the Avalon CT, Hydro, the Consumer Advocate, Newfoundland Power, and the IIC Group do not intend to present evidence, examine, cross-examine or present argument in relation to the Settled Issues beyond that which is reasonably necessary to assist the Board's understanding, and to explain or clarify Hydro, the Consumer Advocate, Newfoundland Power, and the IIC Group's agreement concerning the Settled Issues.

6. This Settlement Agreement does not preclude the parties from making inquiries, presenting evidence, examining, cross-examining or presenting argument in the applications for Bay d'Espoir Unit 8 and the Avalon CT on issues other than the Settled Issues to evaluate whether those proposed projects are the least-cost alternatives that are in the best interests of customers.

7. This Settlement Agreement represents a reasoned consensus on the Settled Issues and the agreements on individual issues are not intended to be severable.

8. This Settlement Agreement is without prejudice to the positions Hydro, the Consumer Advocate, Newfoundland Power, and the IIC Group may take in proceedings other than those capital budget and related applications intended to implement the recommendations in the 2024 Resource Adequacy Plan to proceed with the addition of Bay d'Espoir Unit 8 and the Avalon CT. It sets no precedent for any issue addressed in this Settlement Agreement in any future proceeding or forum, including, for greater certainty, in future Resource Adequacy Plans.

9. This Settlement Agreement removes the requirement for the experts retained by Hydro, the Consumer Advocate, Newfoundland Power, and the IIC Group to appear before the Board regarding the Settled Issues.

Agreed to as of the 12 day of March, 2025.

For Newfoundland and Labrador Hydro: SWalsh

For the Consumer Advocate: [signature]

Stephen Fitzgerald, KC
Barrister, NL

For Newfoundland Power: ________________________

For the Island Industrial Customer Group: ________________________

For the Labrador Interconnected Group: ________________________
(Signing only to the extent to reflect agreement to Item 1 in the attached Settled Issues List, and without prejudice to any positions taken in future with respect to Labrador)

For Board Hearing Counsel: ________________________

For Newfoundland Power: Dominic Foley ________________ Dominic J. Foley
Barrister, Solicitor, Notary Public (NL)

For the Island Industrial Customer Group: ________________

For the Labrador Interconnected Group: ________________
(Signing only to the extent to reflect agreement to Item 1 in the attached Settled Issues List, and without prejudice to any positions taken in future with respect to Labrador)

For Board Hearing Counsel: ________________

For Newfoundland Power: ______________________________

For the Island Industrial Customer Group: ______________________________

For the Labrador Interconnected Group: ______________________________
(Signing only to the extent to reflect agreement to Item 1 in the attached Settled Issues List, and without prejudice to any positions taken in future with respect to Labrador)

For Board Hearing Counsel: Maureen P. Greene

Attachment 1

Reliability and Resource Adequacy

Settled Issues

March 11, 2025

1. Planning for the Island and Labrador should continue to be completed separately.

2. The load forecast methodology used by Newfoundland and Labrador Hydro (Hydro) in the Long - Term Load Forecast for the Island Interconnected System completed in 2023 and filed with the Board on March 28, 2024 (the 2023 Load Forecast) is consistent with utility industry standards.

3. The 2023 Load Forecast for the Island Interconnected System provides a reasonable range of provincial load growth over the 2023-2034 period. The 2023 Load forecast for the Island Interconnected System will be updated for 2024 and filed with the Board in the first quarter of 2025.

4.
   (1) In developing its recommendations, Hydro developed a range of planning criteria and a range of load forecasts that are used in relevant scenarios for the Island Interconnected System. The range of planning criteria applied by Hydro, while they continue to be subject to review, are adequate to employ at this time for resource adequacy and reliability planning for the Island Interconnected System. The scenarios outlined in the 2024 Resource Adequacy Plan demonstrate the need for new capacity on the Island Interconnected System.

   (2) Hydro's system planning criteria will continue to be studied for appropriateness for future system planning purposes. Hydro will review the criteria and report on the criteria applicability for planning purposes in its 2026 Resource Adequacy Plan

5. Holyrood Thermal Generating Station and Hardwoods and Stephenville Gas Turbines are required in the near term, as part of the Bridging Plan, until new generation has been reliably integrated into the Island Interconnectedsystem.

6. The potential feasible supply options identified and modelled within Hydro's supply stack as outlined in the 2024 Resource Adequacy Plan are an appropriate basis for Hydro to proceed with an application in 2025 for approval for new capacity including an application for Bay d'Espoir Unit 8 and the Avalon CT. Hydro will further study potential feasible supply options for the 2026 Resource Adequacy Plan to meet the Reference Case.

7. Hydro's use of Class 5 cost estimates is reasonable for the analysis of resource options within the 2024 Resource Adequacy Plan.

8. Hydro analyzed an appropriate range of scenarios and sensitivities for the analysis included in the Resource Adequacy Plan to determine its recommendations regarding the minimum investment required being Bay d'Espoir Unit 8 and the Avalon CT.

9. The 2023 Load Forecast and the reliability planning analysis outlined in the 2024 Resource Adequacy Plan demonstrate that additional capacity is required for the Island Interconnected system in the period 2031-2034 with the amount of capacity depending on the case and scenario analyzed. The Reference Case results indicate that approximately 524 MW of capacity is required by 2034. The Minimum Investment Expansion Plan which is based on the Slow Decarbonization load forecast results indicate a minimum of 385 MW of new capacity is required by 2034.

10.

(1) The recommendation to build a new 154 MW unit at Bay d'Espoir and a 150 MW combustion turbine on the Avalon Peninsula, which is based on the Slow Decarbonization Case, is appropriate as part of the first step in addressing the requirements for additional capacity for the Island Interconnected system and applications for these projects should be evaluated at this time. Hydro will file an application in the first quarter of 2025 for approval of new generation for a new 154 MW unit at Bay d'Espoir and a 150 MW combustion turbine on the Avalon Peninsula.

(2) Hydro will report to the Board semi-annually on all work ongoing relating to planning for the reliability and resource adequacy for the Island Interconnected system. The first semi-annual report will be filed in Q4 of 2025, and in Q2 and Q4 of each year thereafter. A 2026 Resource Adequacy Plan will be filed with the Board in the fourth quarter of 2026.

(3) The inclusion of wind energy for meeting firm energy requirements will continue to be studied. Hydro will report to the Board in the semi-annual report filed in the fourth quarter of 2025 on the status of ongoing analysis and the EOI which Hydro plans on undertaking in 2025.

(4) Hydro will continue to plan for the current and future reliability and resource adequacy for the Island Interconnected system and will continue to file with the Board the studies listed in the attached Schedule A as the studies are completed unless noted in the Schedule. Hydro will advise the Board on the status of the studies listed in Schedule A in its semi-annual report, including identifying any new study being undertaken.

11. The terms used in this Issues List have the same meaning as in the 2024 Resource Adequacy Plan.

Schedule A to Settled Issues List

Currently Planned Studies to Meet Reference Case Requirements

Driver	Key Activity	Description	Anticipated Completion Date[1]	Notes
Minimum Investment Expansion Plan	BDE Unit 8 and On-Avalon CT Capital Budget Application	The application to build BDE Unit 8 and the On-Avalon CT form the baseline to meet the Reference Case requirements.	Q1 2025	As per Hydro's response to PUB-NLH-336 of the2024 Resource Adequacy Plan proceeding, Hydro intends to file the application no later than March 31, 2025.
	Supply EOI Process	This process, which encompasses both the Supply EOI and a Request for Proposal process, is anticipated to be a multi-year process, depending on the number of applicants, and commercial negotiations. However, it is anticipated that by Q1 2026, PPA cost information will be available for inclusion into the 2026 Reliability and Resource Adequacy analysis.	Q4 2026	Due to commercial considerations, Hydro does not intend to file its Supply EOI Evaluation on the record; however, it will ensure the Board of Commissioners of Public Utilities and the parties are informed of the outcomes and next steps through the agreed upon semi-annual reporting.
Bridging Period Timeline	Holyrood Thermal Generating Station Bridging Plan Refresh	This study will provide a refresh on the capital and operating costs for Holyrood up to 2035.	Q1 2025	The results of this study will be filed upon its completion and internal review[2] by Hydro.
Transmission Planning	The Final Lower Churchill Project Operational Study (Stage 4F)	This study is the final stage of a series of studies with the primary objective of establishing the "Final UFLS[3] Scheme" and developing the LIL transfer limits based on this proposed scheme	Q2 2025	The results of this study will be filed upon its completion and internal review by Hydro.

[1] This date is subject to change depending on a variety of factors. Hydro will report to the Board, copied to the Parties, semi-annually on all work ongoing relating to planning for the reliability and resource adequacy for the Island Interconnected system. The first semi-annual report will be filed in Q4 of 2025, with the following reports filed in Q2 and Q4 of each year thereafter.

[2] Hydro's internal review, as referenced herein, will be completed within 45 days of the completion of the report. Should additional time be required to complete the internal review, Hydro will advise the Board and the parties of the amount of additional time needed, and the reasons for the additional time.

[3] Under Frequency Load Shedding ("UFLS").

Schedule A to Settled Issues List

Driver	Key Activity	Description	Anticipated Completion Date[1]	Notes
	Evaluation of BESS for Frequency Support	This study will evaluate the feasibility of a BESS in the their ability to provide frequency support to the Island system in an attempt to improve the LIL to Maritime Link relationship	Q4 2025	The results of this study will be filed upon its completion and internal review by Hydro.
	Evaluation of a Remedial Action Scheme ("RAS") for the Avalon 230 kV Corridor	This study will evaluate the feasibility of a RAS that aims at mitigating thermal overloads and low voltage conditions that limit BDE to SOP flow when the LIL is out of service.	Q4 2025	The results of these studies have directly related implications. They will be filed together once complete and after an internal review by Hydro. If the results indicate that a Transmission Expansion Application is necessary, the studies will accompany the application; otherwise they will be provided as an independent filing.
	Transmission Expansion Feasibility Study	BDE to SOP Transmission Capacity Expansion	Q4 2025	
Long-Term Fuel Supply Security	Marine Terminal Station FEED[4]	FEED work to support a capital budget application for a Marine Terminal. Such FEED work could (i) reduce fuel supply constraints for a future CT addition within the Reference Case Expansion Plan; and, (ii) provide increased efficiency in fuel delivery for Hydro's recommended 150 MW CT as a part of the Minimum Investment Expansion Plan.	Q3 2025	As is the practice with FEED work, this analysis will be filed with the Marine Terminal Station Capital Budget Application, if necessary, and not as stand-alone reporting.
Reference Case Expansion Plan	CDM Potential Study	Hydro will assess the recommendations of the 2024 CDM Potential Study to develop the next multi-year plan for ECDM.[5] Hydro will evaluate incorporation of CDM programming as a supply stack option in the next Resource Adequacy Plan.[6]	Q2 2025	Joint Utility ECDM 2026–2030 Plan[7]

[4] Front-End Engineering and Design (FEED").
[5] Anticipated to be filed in the fourth quarter of 2025.
[6] The feasibility of ECDM as a supply stack option is dependent on the findings of the ECDM Potential Study.

Schedule A to Settled Issues List

Driver	Key Activity	Description	Anticipated Completion Date[1]	Notes
	ELCC Study	To inform the 2026 Resource Adequacy Plan supply stack, the ELCC Study will determine the ELCC of batteries, wind, solar, and may also include demand response measures.	Q4 2025	The results of this study will be filed upon its completion and internal review by Hydro.
	2025 Load Forecast Update	The 2025 load forecast will form the baseline for the next Resource Adequacy Plan analysis and the Reference Case Expansion Plan.	Q4 2025	This document will be filed upon its completion and internal review by Hydro.
	Battery Feasibility Study	To inform the 2026 Resource Adequacy Plan supply stack, Hydro will advance the BESS project to the feasibility stage. The practicality and viability of the project will be examined and engineering will be advanced to a level appropriate to commence FEED if the project is deemed viable.	Q1 2026	The results of this study will be filed upon its completion and internal review by Hydro.
	Cat Arm Unit 3 Feasibility Study	To inform the 2026 Resource Adequacy Plan supply stack, Hydro will advance the Cat Arm Unit 3 project to the feasibility stage. The practicality and viability of the project will be examined and engineering will be advanced to a level appropriate to commence FEED if the project is deemed viable.	Q1 2026	The results of this study will be filed upon its completion and internal review by Hydro.

Schedule 3

Schedule 3

Expansion Plan Update

Project Justification

Contents

List of Appendices

1.0 Introduction

On July 9, 2024, Newfoundland and Labrador Hydro ("Hydro") filed its 2024 Resource Adequacy Plan, the latest update in Hydro's *Reliability and Resource Adequacy Study Review* proceeding ("*RRA Study Review*") before the Board of Commissioners of Public Utilities ("Board").[1] The focus of the 2024 Resource Adequacy Plan was to recommend an Expansion Plan[2] to satisfy the loss of load criteria while ensuring sufficient resources to meet operational reserves and energy requirements for the Island Interconnected System. 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 Labrador-Island Link ("LIL").

Supply expansion decisions are based on Hydro's previously established[3] resource planning criteria,[4] detailed as follows:

- **Probabilistic Capacity:** The Island Interconnected System should have sufficient generating capacity to satisfy a loss of load hours ("LOLH") expectation target of not more than 2.8 hours per year.[5,6]
- **Energy:** The Island Interconnected Systems should have sufficient generating capability to supply all its firm energy requirements with firm system capability.

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

[2] For further information on the systematic process followed by Hydro to develop the recommended Expansion Plan for the Island Interconnected System, please refer to the "2024 Resource Adequacy Plan – An Update to the Reliability and Resource Adequacy Study," Newfoundland and Labrador Hydro, rev. August 26, 2024 (originally filed July 9, 2024) ("2024 Resource Adequacy Plan"), app C.

[3] The establishment of the probabilistic capacity criteria occurred in the 1980s and the firm energy criteria in the 1990s.

[4] For further information on how Hydro is planning to meet these criteria, please refer to the 2024 Resource Adequacy Plan, app. C.

[5] The previous resource adequacy target of two outage days in ten years, or a loss of load expectation ("LOLE") of 0.2, was chosen at the time over the alternative criteria of one day in ten years, or 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 LOLH of 2.8 hours per year.

[6] Further discussion on 0.1 LOLE versus 2.8 LOLH planning criteria can be found in the 2024 Resource Adequacy Plan, app. B, sec. 5.1.7.

In 2018, additional capacity criteria was established by Hydro,[7] 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.[8]

Due to the separation of planning criteria for the Island Interconnected System and the Labrador Interconnected System, Hydro's 2024 Resource Plan focused on the expansion of the Island Interconnected System only for the study period 2024 through 2034.

Throughout the *RRA Study Review*, and in line with Hydro's legislated 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

To ensure prudency, Hydro updated the Expansion Plan analysis with the 2024 Load Forecast to confirm that the need for additional energy and capacity remains, as the analysis completed for the 2024 Resource Adequacy Plan was based on the 2023 Load Forecast. In addition, with both the Avalon

[7] "Reliability and Resource Adequacy Study," Newfoundland and Labrador Hydro, rev. September 6, 2019 (originally filed November 16, 2018).
[8] 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.

Combustion Turbine ("CT") and Bay d'Espoir ("BDE") Unit 8 Class 3 cost estimates, the Expansion Plan analysis was updated to demonstrate that these resource options remain least cost.

Hydro's updated analysis has confirmed that the capacity options identified in 2024 Resource Adequacy Plan—both BDE Unit 8 and the Avalon CT—are required and remain the least-cost resource options to meet system reliability.

This schedule details the analysis undertaken by Hydro, with the evidence divided into six sections, specifically:

1) **Summary of 2024 Resource Adequacy Plan Recommendation (Section 2.0):** The recommended Minimum Investment Required Expansion Plan for the Island Interconnected System, in consideration of retiring assets and meeting all criteria as identified above.
2) **Summary of 2024 Load Forecast Update (Section 3.0):** An overview of the 2024 Load Forecast and a comparison against the 2023 Load Forecast. A detailed report on the methodology andcomponents of the 2024 Load Forecast can be found in Appendix A of this schedule.
3) **Firm Energy Requirements (Section 4.0):** The firm energy requirements for the Island Interconnected System are provided through energy load resource balance plots for the 2024 Slow Decarbonization and Reference Case load forecast scenarios and in consideration of retiring assets.
4) **Expansion Plan Update (Section 5.0):** This section provides an overview of the eight sensitivities that were developed to test Expansion Plan Scenario 1 (Reference Case) and Scenario 4 (Minimum Investment Required).
5) **Further Testing of the Expansion Plans (Section 6.0):** This section describes the additional analysis conducted for specific Expansion Plans as follows:
    - Compliance with the final *Clean Electricity Regulations* ("*CER")*;[9]
    - The LIL Shortfall Analysis: to determine the level of shortfall that remains should the LIL be offline on an extended bipole outage;

[9] Government of Canada. (2024). *Clean Electricity Regulations: SOR/2024-263.* Canada Gazette, Part II, Volume 158, Number 26. https://www.gazette.gc.ca/rp-pr/p2/2024/2024-12-18/html/sor-dors263-eng.html

- On-Avalon Transmission Constraints: A summary of the least-cost transmission upgrade required to alleviate trapped off-Avalon generation during a LIL bipole outage, as described in the 2024 Resource Adequacy Plan.[10]

6) **Recommended Expansion Plan and Conclusion (Section 7.0 and 8.0):** This section confirms the resource requirements identified in the Minimum Investment Required Expansion Plan in the 2024 Resource Adequacy Plan as continuing to be the recommended capacity resource options for the 2025 Build Application.

2.0 Summary of 2024 Resource Adequacy Plan Recommendation

Hydro's approach within its 2024 Resource Adequacy Plan sought to de-risk the initial investment decision. System reliability, retirement of aging assets, and load growth were the main drivers of capacity and energy requirements in Hydro's Expansion Plans. Recognizing the uncertainties that remain for each, Hydro's strategy was to recommend an expansion plan that meets reliability criteria under the Minimum Investment Required scenario[11] (i.e., the least amount of resource additions) while balancing cost and environmental considerations. This strategy considers a highly reliable LIL (1% LIL bipole EqFOR)[12] and Slow Decarbonization load forecast. Hydro recognizes that this expansion plan does not meet the reliability requirements of the expected case, which considers a 5% LIL bipole EqFOR and Reference Case load forecast. 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 scenario, is substantial and Hydro considers this the first step.

The recommended Expansion Plan that was put forward is Scenario 4AEF(ADV).1 (Minimum Investment Required), which is summarized in Table 1. This Expansion Plan includes BDE Unit 8 and Avalon CT coming into service in 2031 and up to 400 MW of installed wind capacity by 2034 to meet firm energy

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[10] Please refer to the 2024 Resource Adequacy Plan, app. C, sec. 7.3.
[11] Scenario 4 (Minimum Investment Required or S4): Represents the scenario requiring the minimum investment (least amount of resource additions) based on a high level of LIL reliability (1% LIL bipole equivalent forced outage rate) 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.
[12] Equivalent Forced Outage Rate ("EqFOR").

planning criteria, resulting in approximately an additional 385 MW of firm capacity and 1.4 TWh of firm energy added to the Island Interconnected System within the next ten years. The green highlighting indicates the addition of one or more units in that year.

Table 1: Recommended Expansion Plan – 2024 Resource Adequacy 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, and reduce costs associated with maintaining and operating these 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 previously;
- Considers the least-cost transmission upgrade required to alleviate the On-Avalon bottleneck during a LIL bipole outage;[13]

[13] As mentioned in the 2024 Resource Adequacy Plan, Hydro is actively trying to reduce the identified least-cost transmission upgrade through the implementation of an Remedial Action Scheme ("RAS") and/or Dynamic Line Rating ("DLR"). Please refer to 2024 Resource Adequacy Plan, app. c., sec. 7.3.

- Includes an Avalon CT plant with synchronous condenser 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 supply availability on the Island;
- Helps reduce the reliance on aging thermal assets by enabling retirement of these assets;
- BDE 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 final *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%.

Hydro recognizes that while the recommended Minimum Investment Required Expansion Plan provides a balance between cost, 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 Adequacy Plan. Any additional requirements will be identified in the next Resource Adequacy Plan.

Hydro has gained consensus on a number of issues within the 2024 Resource Adequacy Plan described in a Settlement Agreement provided as Schedule 2 to this application.

3.0 Summary of 2024 Load Forecast Update

The load forecast is a key input to the resource planning process that projects electric power demand and energy requirements through future periods. Hydro annually develops a Reference Case forecast 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 resultant load forecast is a critical input to Hydro's overall planning, budgeting, and operating activities. The 2024 Load Forecast was produced in the third quarter of 2024; it covers the period from 2024 through 2035.

Hydro's 2024 Load Forecast presents a slightly more conservative outlook compared to the 2023 forecast; however, the difference is not material in the Reference Case or in the Slow Decarbonization scenarios.

Overall, the 2024 Load Forecast is showing growth across the provincial system, stemming from several factors including:

- The recent increase in forecast population and related home construction utilizing Government of Newfoundland and Labrador ("Government") forecasts;
- Ongoing electrification[14] 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 Energy + Climate Advisors ("Dunsky") for electric vehicle ("EV") adoption rates; and
- Existing Industrial customers firm requests to expand and/or decarbonize their operations.

Although a range of load forecasts were developed independently for the Island Interconnected System and the Labrador Interconnected System, for this report Hydro has only included the Island Interconnected System load forecast as it relates to the 2025 Build Application.[15] Consistent with the forecasts used in the 2024 Resource Adequacy Plan, three forecasts were developed to reflect the range of forecasted Island Interconnected System load requirements, as summarized in Figure 2.

[14] Electrification is decarbonization that results in replacing processes or technologies that use fossil fuels with an electrically powered equivalent.
[15] The 2024 Load Forecast is provided as Appendix A.

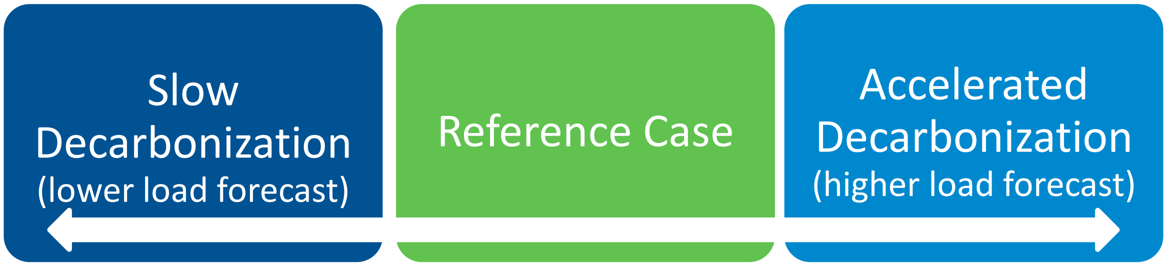

Figure 2: Island Interconnected System Forecast Scenarios

- **Slow Decarbonization Path Scenario ("Slow Decarbonization"):** Considers more moderate decarbonization efforts and electrification of the transportation sector, lower population and housing starts, and current industrial demand, 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, and anticipated electrification of the transportation sector. Also included is a slight increase in industrial growth and a near-term increase in population and housing starts; and
- **Accelerated Decarbonization Path Scenario ("Accelerated Decarbonization"):** Assumes accelerated decarbonization and electrification of the transportation sector. Economic indicators are consistent with the Reference Case and an increase in industrial demand is modelled. This results in a higher load forecast as compared to the Reference Case.

In the 2024 Resource Adequacy Plan, the recommended Expansion Plan, referred to as the Minimum Investment Required Expansion Plan, includes the Slow Decarbonization load forecast. The capacity resource options identified in the Minimum Investment Required Expansion Plan, BDE Unit 8 and a 150 MW Avalon CT, have both been put forth in the 2025 Build Application. While the 2024 Resource Adequacy Plan recommends to build for the Slow Decarbonization load forecast, the most likely forecast scenario remains the Reference Case load forecast, and the 2026 Resource Adequacy Plan will include a recommended Expansion Plan to meet the Reference Case load forecast.[16]

[16] The 2026 Resource Adequacy Plan analysis will incorporate the 2025 Load Forecast update.

The 2024 Reference Case load forecast reflects stability in government policies, incentives and programs for decarbonization and electrification during the past year. The province continues to see economic growth, increase in population and housing starts, consistent conversions from oil to electric and an increase but steady adoption of EVs. Industrial load continues to increase primarily attributable to an increase in mining load.

The 2024 Slow Decarbonization load forecast scenario also reflects stability in government incentives and policies for decarbonization. This scenario continues to consider slower economic activity, a slower population growth and lower housing starts compared to the Reference Case load forecast. This scenario also reflects a slower decarbonization impact, lower oil-to-electric conversions and a slower adoption of EVs. There is 10 MW included for future increase in industrial activity and current customers are maintained at their existing operating levels.

3.1 Customer Demand Comparison

For reference, Chart 1 compares the 2024 and the 2023 Slow Decarbonization and Reference Case load forecast scenarios.

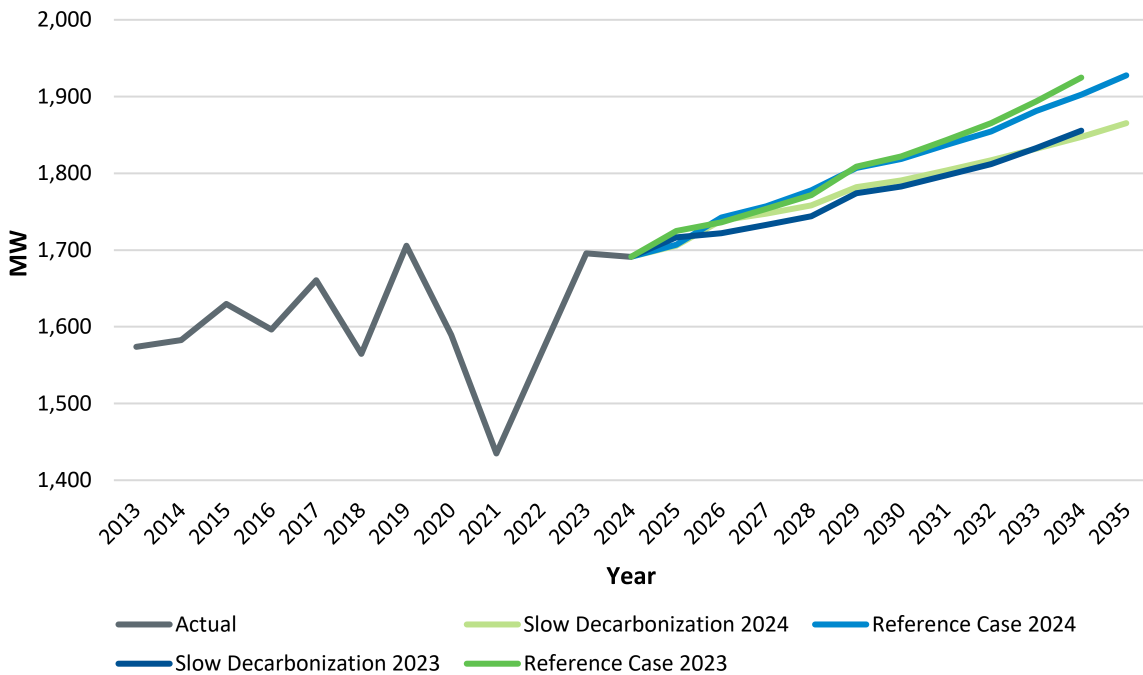

Chart 1: Island Interconnected System Annual Customer Coincident Demand Requirements Comparisons[17,18,19]

The 2024 Load Forecast is slightly more conservative in both the Slow Decarbonization and Reference cases when compared to the 2023 forecast. The 2024 Reference Case load forecast demand reduced by 1.2%, or 22 MW by 2034 compared to the demand requirement identified in the 2023 Reference Case load forecast. In addition, the 2024 Slow Decarbonization load forecast demand reduced by 0.4%, or 8 MW by 2034 as compared to the demand requirement identified in the 2023 Slow Decarbonization load forecast. The slight decline is reflective of updated economic activity inputs, such as housing starts.

[17] The Island Interconnected System annual customer coincident demand is reflective of the total Island Interconnected System demand less transmission losses and station service load.
[18] Historical values are not weather-normalized.
[19] The significant decline in demand in 2020 and 2021 was due to the effects of the COVID-19 pandemic.

3.2 Energy Requirements Comparison

As shown in Chart 2, the 2024 Slow Decarbonization and Reference Case forecasts reflect a slight reduction compared to the corresponding 2023 forecasts.

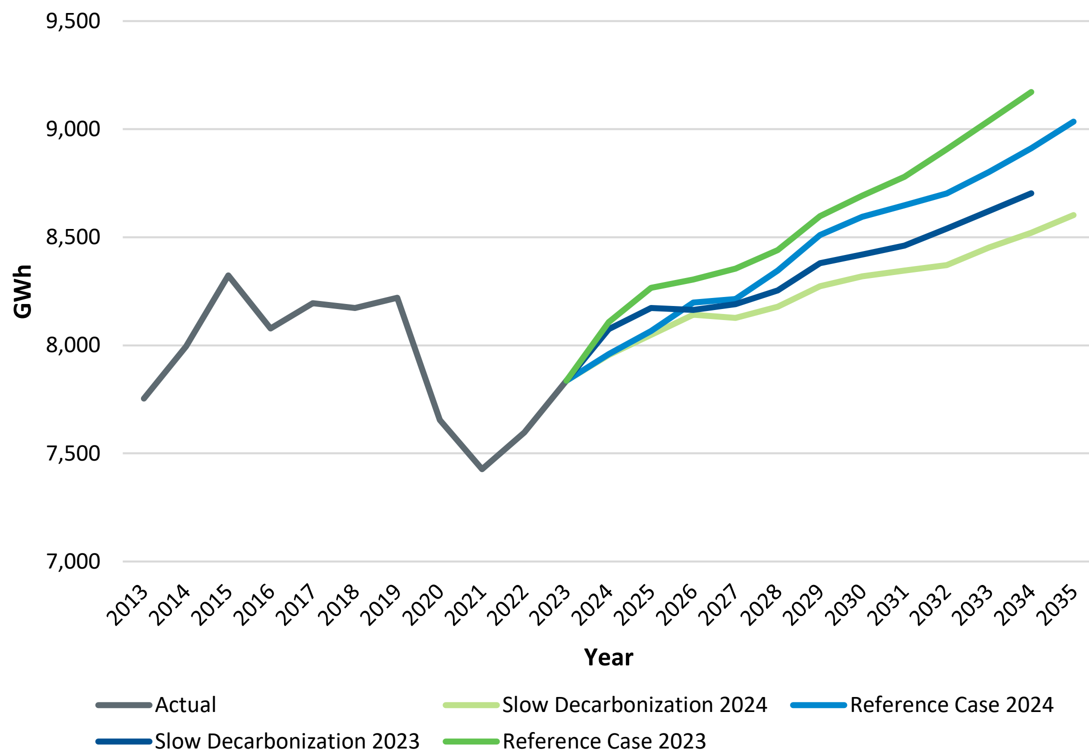

Chart 2: Island Interconnected System Annual Energy Requirements Comparisons[20,21]

Similar to the demand forecast, the 2024 energy forecast is slightly more conservative in both the Slow Decarbonization and Reference cases when compared to 2023. The 2024 Reference Case load forecast energy reduced by 2.8%, or 238 GWh by 2034 compared to the energy requirement identified in the 2023 Reference Case load forecast. In addition, the 2024 Slow Decarbonization load forecast energy reduced by 2.1%, or 169 GWh by 2034 as compared to the energy requirement identified in the 2023 Slow Decarbonization load forecast. The slight decline is reflective of updated technology changes such as mini split heat pumps and an increase in electricity rates compared to the 2023 Load Forecast.

[20] Historical values are not weather-normalized.
[21] The significant decline in energy in 2020 and 2021 was due to the effects of the COVID-19 pandemic.

3.3 2024 Load Forecast Conclusion

At a minimum, the Slow Decarbonization scenario is forecasting additional demand of 174 MW and 0.6 TWh of energy required by 2035. Comparing against the 2023 Slow Decarbonization scenario, the demand reduced by 0.4%, or 8 MW by 2034, which is a negligible difference.

Hydro is confident that its 2024 Load Forecast provides comprehensive input into the analysis supporting the 2025 Build Application to ensure appropriate planning for the future of the provincial electricity grid.

4.0 Firm Energy Requirements

This section provides an overview of the Island Interconnected System firm energy requirements over the study period that has been updated since filing the 2024 Resource Adequacy Plan to account for the 2024 Load Forecast update. The firm energy load resource balances for each year in the planning horizon for two Island Interconnected System load scenarios—Slow Decarbonization and Reference Case, are provided in Chart 3 and Chart 4.

In each chart, the existing resources are identified by stacked columns; 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 Inc. ("Newfoundland Power") hydro resources, hydroelectric facilities at Deer Lake and Exploits, and other Non-Utility Generators such as CBPP[22] 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.

[22] Corner Brook Pulp and Paper Limited ("CBPP").

4) NLH Holyrood: Includes energy from the Holyrood Thermal Generation Station ("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.

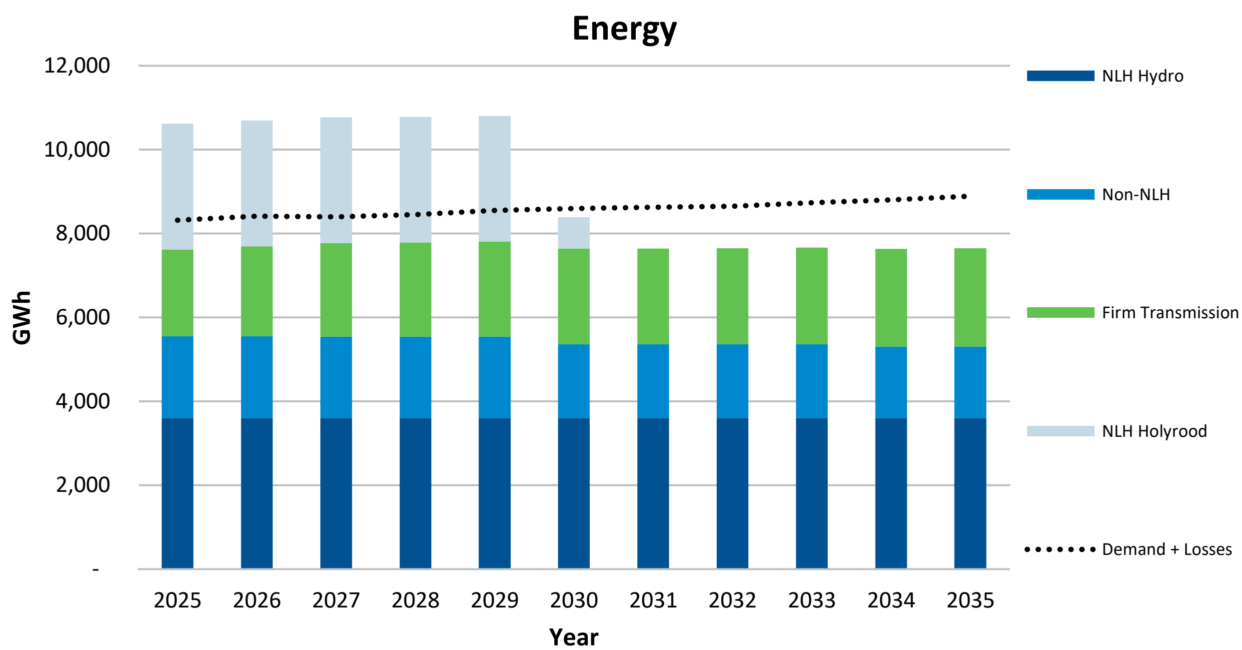

Chart 3: Island Firm Energy – Slow Decarbonization Load Forecast

[23] The units at the Holyrood TGS, Hardwoods Gas Turbine ("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.

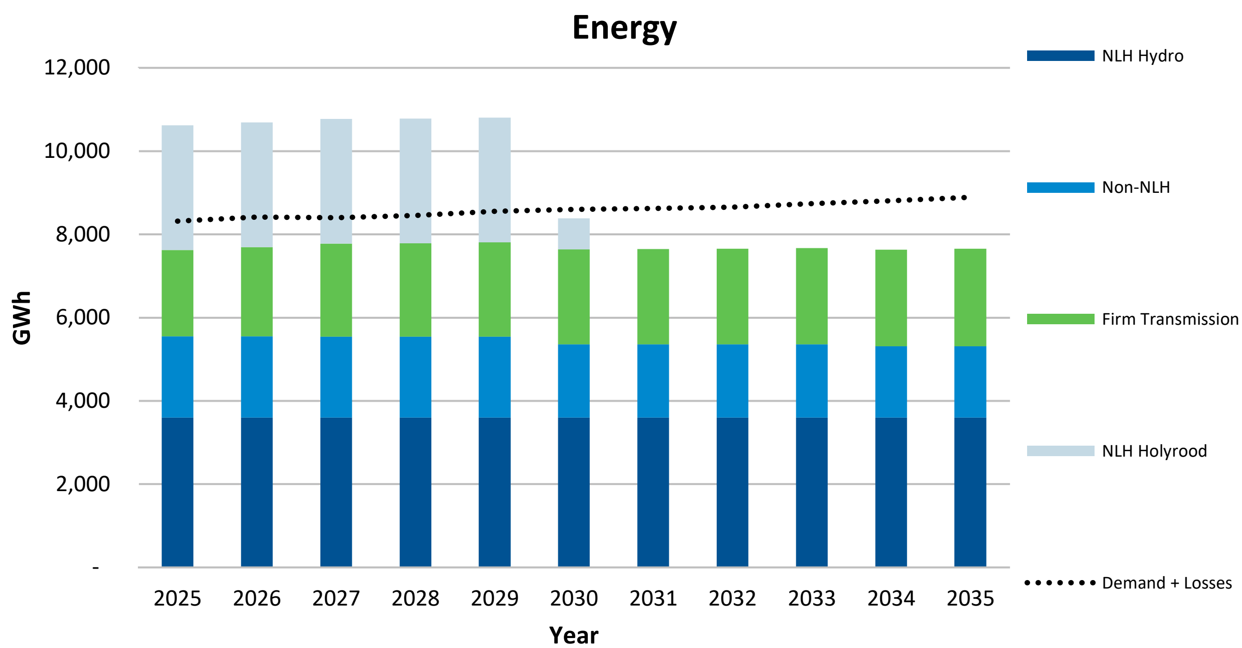

Chart 4: Island Firm Energy – Reference Case Load Forecast

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 assumed to be to retired at the end of the first quarter of 2030. An additional firm energy source will be required immediately following the retirement of the Holyrood TGS in all load forecast scenarios.

To begin the process of meeting firm energy requirements identified in 2030, Hydro will issue a supply Expression of Interest (“EOI”) for the Island Interconnected System by the end of the second quarter of 2025. 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 requests for proposals for consideration. In addition, Hydro recognizes that there could be a benefit to renewing existing energy power purchases agreements 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. Lastly, Hydro is pursuing further studies in support of reliability and supply adequacy, specifically potential mitigations for the LIL to Maritime Link relationship to maximize power delivery to the Island which could, in turn, reduce the amount of firm energy requirements demonstrated in the charts above. These outcomes will inform the EOI process, which will be conducted in parallel to the build application process in 2025 to help determine resource options and costs to meet the Island Interconnected System energy requirements; however, these potential mitigations will not reduce the capacity requirements for the Island Interconnected System identified in this application.

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 less energy is required and the units are typically offline. Non-dispatchable, renewable energy options (i.e., wind) provide less flexibility since there is no control over the availability of fuel (i.e., wind) at any given time. This could lead to the potential for increased spill from hydraulic resources on the Island Interconnected System and/or limit the amount of LIL energy that is brought to the Island.

5.0 Expansion Plan Update

5.1 Expansion Plan Scenarios

Hydro established eight main scenarios as the basis for the Expansion Plan analysis in the 2024 Resource Adequacy Plan. The variables that were altered between scenarios include the capacity planning criteria, the LIL bipole EqFOR, the corresponding Planning Reserve Margins, and the Island Interconnected System load forecast. For the purposes of the 2025 Build Application analysis, only Scenarios 1 (Reference Case) and Scenario 4 (Minimum Investment Required) were assessed. Table 2 provides a summary of the underlying major inputs for each scenario.

Table 2: Summary of Expansion Plan Scenarios Analyzed in 2025 Build Application

Scenario	Capacity Planning Criteria (LOLH)	LIL Bipole EqFOR (%)	Planning Reserve Margin[24,25] (%)	Island Interconnected System Load Forecast
1	2.8	5	25.8	Reference
4	2.8	1	17.1	Slow Decarbonization

[24] The Planning Reserve Margins presented here are inclusive of losses.
[25] For further information on calculation of planning reserve margins, please refer to the 2024 Resource Adequacy Plan, app. B, sec. 5.1.7.

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.
- **Scenario 4 (Minimum Investment Required):** Represents the scenario requiring the minimum investment (i.e., 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 forecast) that can be reasonably anticipated on the Island Interconnected System. This scenario was intended to bookend the Expansion Plan scenarios created in the 2024 Resource Adequacy Plan by identifying the Minimum Investment Required on the Island Interconnected System.

5.2 2025 Build Application Sensitivities

In the 2024 Resource Adequacy Plan, Hydro initially established 11 sensitivities to test select scenarios.[26] Ultimately, the recommended Expansion Plan that was put forward was Scenario 4AEF(ADV).1 (Minimum Investment Required) as depicted in Table 1 in Section 2.0. Therefore, sensitivity "AEF" was included as the starting point for the Build Application analysis. Sensitivity "AEF" considers a fixed wind profile to meet Hydro's firm energy criteria,[27] excludes batteries as a resource option,[28] and limits the number of CTs that can be constructed to one, approximately 150 MW On-Avalon CT in consideration of current diesel fuel supply availability on the Island.

For the purposes of this build application, an additional seven sensitivities were created in addition to sensitivity "AEF" to test Scenario 1 (Reference Case) and Scenario 4 (Minimum Investment Required).

[26] Please refer to the 2024 Resource Adequacy Plan, app. C, sec. 6.2.
[27] Hydro's firm energy criteria is such that the Island Interconnects System should have sufficient generating capability to supply all its firm energy requirements with firm system capability.
[28] Based on analysis performed by Hydro as part of the *RRA Study Review*, battery energy storage systems ("BESS") are emerging as a viable supply solution worthy of further consideration. However, there remain appreciable feasibility concerns surrounding BESS solutions related to capability in emergency scenarios such as an extended outage to the LIL bipole. Given concerns regarding BESS solutions in the event of a LIL shortfall scenario, such solutions were not included as capacity resources in the Minimum Investment Required Expansion Plan (i.e., the recommended expansion plan). Additional information can be found in response to PUB-NLH-339 of the *RRA Study Review*. Hydro is committed to further study of battery effective load carrying capability ("ELCC") to inform the 2026 Resource Adequacy Plan as outlined in response to PUB-NLH-334.

Most sensitivities are slight modifications, or combinations, of the sensitivities included in the 2024 Resource Adequacy Plan; therefore, the lettering format remained the same as what was done in the 2024 Resource Adequacy Plan for consistency. These sensitivities are summarized in Table 3.

Table 3: Build Application Sensitivities

Sensitivity	Description
AEF	Fixed wind profile to meet firm energy criteria, removes batteries as a resource option, and limits CT additions to 150 MW in consideration of current diesel fuel supply availability on the Island.
AEFC	A combination of Sensitivities AEF and C to determine the impact of removing forced CT fuel burn-off.
AEFD	Same as sensitivity AEF with the exception of including the P85 costs for BDE Unit 8 and other hydro resource options.
AEFG	A combination of Sensitivities AEF and G to determine the impact of increasing CT fuel costs to $2.05/L[29] in consideration of potential future volatility in fuel costs.
AEFH	Same as sensitivity AEF with the exception of including the P85 costs for the On-Avalon CT.
AEFDH	A combination of Sensitivities AEF, D and H to determine the impact of an increase in costs for both BDE Unit 8 and the Avalon CT, by including the P85 costs for both BDE Unit 8 and the Avalon CT.
AEFGH	A combination of Sensitivities AEF, G and H to determine the impact of increasing the CT capital cost in addition to an increase in CT fuel costs.
AEFJ	Same as sensitivity AEF with the exception of including the potential for the Clean Electricity Investment Tax Credit[30] cost savings.

A further discussion, including the results, follows in Sections 5.2.1 to 5.2.2.

5.2.1 Scenario 1: Reference Case

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 provided in the following sections:

- Resource Requirements (Section 5.2.1.1);

[29] $2.05/L reflects the high case provided by Stantec's Fuel Market Study, which Hydro escalated after 2024. This cost is currently approximately 55% higher than the current cost of $1.13/L. For reference, the 2024 Resource Adequacy Plan analysis assumed a 50% fuel cost increase as reflected in Sensitivity AEG of that study .

[30] Government of Canada. (2024). *Clean Electricity Investment Tax Credit for Provincial and Territorial Crown Corporations.* 2024 Fall Economic Statement. https://budget.canada.ca/update-miseajour/2024/report-rapport/tm-mf-en.html

- NPV Comparison (Section 5.2.1.2); and
- Annual Emissions Comparison (Section 5.2.1.3).

5.2.1.1 Resource Requirements

Scenario 1 includes the Reference Case load forecast, assumes a LIL bipole EqFOR of 5%, and a probabilistic planning criteria of 2.8 LOLH as summarized in Table 2 in Section 5.1. The results of the Expansion Plan sensitivities are summarized in Table 4 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 4 shows the results for 2030 through 2035.[31] 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.[32] 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 net present value ("NPV") and annual greenhouse gas ("GHG") emissions are included for each Expansion Plan sensitivity, and are summarized in Sections 5.2.1.2 and 5.2.1.3, respectively.

In all the sensitivities of the Reference Case scenario analyzed, including escalation of both BDE Unit 8 and Avalon CT to the Authorized Budget (P85), the model does not change the Expansion Plan outcome.

The model shows that the following resources are required to meet the requirements of the Reference Case:

- In-service dates of 2031 for both Avalon CT and BDE Unit 8;
- Cat Arm Unit 3 in-service date of 2032;

[31] The planning horizon for the 2024 Resource Adequacy Plan ended in 2034. For the purposes of the 2025 Build Application, the planning horizon was extended by one year, to 2035, to reflect the 2024 Load Forecast time horizon.
[32] The Bridging Period is defined as the period from present until 2030, the year in which aging thermal assets are planned to be retired. During the Bridging Period, the system would rely primarily on existing sources of generation capacity to maintain reliability until 2030, or until such time that sufficient alternative generation is commissioned, adequate performance of the LIL is proven, and generation reserves are met.

- 50 MW of Proxy Capacity in 2034; and,
- 500 MW of Wind by 2035.

The Reference Case Expansion Plan results in approximately an additional 525 MW and 1.8 TWh added to the Island Interconnected System within the next ten years, and the selection of both Avalon CT and BDE Unit 8 coming into service in 2031 as the first steps to meet the Reference Case are common to all scenarios studied.

5.2.1.1.1 Scenario 1AEF: Fixed Wind Profile, No Batteries, and Limit CT

As mentioned previously, sensitivity "AEF" was included as the starting point for the 2025 Build Application analysis. Sensitivity "AEF" considers a fixed wind profile to meet Hydro's firm energy criteria, excludes batteries as a resource option,[33] and limits the number of CTs that can be constructed to one, 150 MW On-Avalon CT in consideration of current diesel fuel supply availability on the Island. The results of this Expansion Plan are summarized in Table 4. All of the Scenario 1 sensitivities produced the same Expansion Plan, and hence this table has not been repeated in the following sections.

Table 4: Scenario 1AEF (Fixed Wind Profile, No Batteries, and Limit CTs)

Resource	Firm Capacity (MW)	Firm Energy (GWh)	2030	2031	2032	2033	2034	2035
BDE Unit 8	154.4	0		1	1	1	1	1
CT	141.6	0		1	1	1	1	1
CAT Unit 3	68.2	0			1	1	1	1
Proxy Capacity	50	0					1	1
Wind 100 MW	22	350	2	4	4	4	5	5
Firm Capacity (MW)			44	384	452	452	524	524
Firm Energy (GWh)			700	1400	1400	1400	1750	1750

[33] Based on analysis performed by Hydro as part of the *RRA Study Review*, battery energy storage systems ("BESS") are emerging as a viable supply solution worthy of further consideration. However, there remain appreciable feasibility questions surrounding BESS solutions related to capability in emergency scenarios such as an extended outage to the LIL bipole. Given concerns regarding BESS solutions in the event of a LIL shortfall scenario, such solutions were not included as capacity resources in the Minimum Investment Required Expansion Plan, (i.e., the recommended expansion plan). Hydro is committed to further study of battery ELCC to inform the 2026 Resource Adequacy Plan. Additional information can be found in Hydro's response to PUB-NLH-339 of the *RRA Study Review*.

For Scenario 1AEF, BDE Unit 8 and one 142 MW CT are required by 2031, followed by Cat Arm Unit 3 by 2032. An additional proxy capacity resource option representing 50 MW of CT generation was also required by 2034. 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 (i.e., 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.

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 400 MW by 2031. As load continues to grow throughout the forecast period, an additional 100 MW of wind is required by 2034. The NPV result of this scenario is $6.7 billion. The annual emissions from 2031 onward are estimated to be 25 kt until 2034 when they increase to 35 kt with the addition of the proxy capacity unit.

Wind is 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.

5.2.1.1.2 Scenario 1AEFC: Fixed Wind Profile, No Batteries, Limit CT, 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. Further study is ongoing to assess extending the shelf life of the fuel in storage, and/or determining if there is a way to cycle unused fuel via new contractual agreements or partnerships 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 included to remove this fuel burn-off requirement; instead, fuel costs are reflective of simulated production requirements, which are much lower. The results of Scenario 1AEFC Expansion Plan that removes the restriction of forcing CT fuel burn-off are unchanged from Scenario 1AEF (Reference Case). The initial least-cost supply options to meet the Reference Case requirements are BDE Unit 8 and the Avalon CT.

The NPV of this scenario is $6.5 billion, approximately $0.2 billion less than Scenario 1AEF (Fixed Wind, No Batteries, and Limit CT). By removing the forced fuel burn-off, the annual emissions after the Holyrood TGS is retired are only 1 kt until 2034 when they increase to 11 kt with the addition of the proxy capacity unit.

5.2.1.1.3 Scenario 1AEFD: Fixed Wind Profile, No Batteries, Limit CT, and Increase Hydro Capital Costs to P85

Another sensitivity was included to reflect the potential for cost overruns of hydro projects. In this sensitivity, the P85 capital cost of BDE Unit 8 was modeled.[34,35] In addition, the percentage increase in costs from the BDE Unit 8 P50 capital cost to the P85 capital cost was applied to the capital cost of all hydroelectric options. The results of this Expansion Plan are unchanged from Scenario 1AEF (Reference Case). The initial least-cost supply options to meet the Reference Case requirements are BDE Unit 8 and the Avalon CT.

The estimated NPV of this scenario is $6.9 billion, $0.2 billion more than Scenario 1AEF. The annual emissions for this scenario after the Holyrood TGS is retired are estimated to be 25 kt until the proxy capacity resource option is constructed in 2034, which increases the annual emissions to 35 kt.

5.2.1.1.4 Scenario 1AEFG: Fixed Wind Profile, No Batteries, Limit CT, and Increase Fuel Costs

Further testing the Avalon CT as a resource option includes increasing the fuel costs in recognition of increasing future demand for diesel fuel in combination with the potential for future supply shortages in Canada.[36] For this scenario, the fuel cost was increased to $2.05/litre and escalated through the study period.[37] The results of this Expansion Plan are unchanged from Scenario 1AEF (Reference Case). The

[34] In all other scenarios, unless otherwise stated, the P50 capital cost for BDE Unit 8 is modeled.
[35] In the 2024 Resource Adequacy Plan, a similar sensitivity was included that increased the capital cost of all hydroelectric resource options, including BDE Unit 8, by 50%. Please refer to the 2024 Resource Adequacy Plan, app. C, sec. 6.2.1.1.7.
[36] For more information, please refer the 2024 Resource Adequacy Plan, app. C, sec. 4.4.1.
[37] The Fuel Market Study is provided in the 2024 Resource Adequacy Plan, app. C, att. 4.

initial least-cost supply options to meet the Reference Case requirements are BDE Unit 8 and the Avalon CT.

Even with an approximately 55% increase to expected future fuel costs, the Avalon CT remains cost-competitive with BDE Unit 8 and remains the least-cost option in comparison to other resource options. The NPV of Scenario 1AEFG is $6.9 billion, a $0.2 billion increase compared to Scenario 1AEF (Fixed Wind, No Batteries, and Limit CTs). The annual emissions for this scenario after the Holyrood TGS is retired are estimated to be 25 kt until the proxy capacity resource option is constructed in 2034, which increases the annual emissions to 35 kt.

5.2.1.1.5 Scenario 1AEFH: Fixed Wind Profile, No Batteries, Limit CT, and Increase CT Capital Costs to P85

Another sensitivity was completed to explore increasing the Avalon CT capital cost to the P85 cost.

The Expansion Plan for Scenario 1AEFH remains the same as all other previous scenarios, indicating that either an increase in fuel cost, or an increase in the Avalon CT capital cost, or an increase in the hydroelectric capital costs does not change the Expansion Plan outcome. The NPV of Scenario 1AEFH is $6.8 billion, $0.1 billion more than Scenario 1AEF (Reference Case). The initial least-cost supply options to meet the Reference Case requirements are BDE Unit 8 and the Avalon CT.

The annual emissions for this scenario after the Holyrood TGS is retired are estimated to be 25 kt until the proxy capacity resource option is constructed in 2034, which increases the annual emissions to 35 kt.

5.2.1.1.6 Scenario 1AEFDH: Fixed Wind Profile, No Batteries, Limit CT, and Increase Hydro and CT Capital Costs to P85

This sensitivity included increasing both the Avalon CT capital cost and the BDE Unit 8 capital cost to the P85 cost. In addition, the percentage increase in costs from the BDE Unit 8 P50 capital cost to the P85 capital cost was applied to the capital cost of all hydroelectric options. The results of this Expansion Plan are unchanged from Scenario 1AEF (Reference case). The initial least-cost supply options to meet the Reference Case requirements are BDE Unit 8 and the Avalon CT.

The NPV of Scenario 1AEFDH is $7.1 billion, $0.4 billion more than Scenario 1AEF. The annual emissions for this scenario after the Holyrood TGS is retired are estimated to be 25 kt until the proxy capacity resource option is constructed in 2034, which increases the annual emissions to 35 kt.

5.2.1.1.7 Scenario 1AEFGH: Fixed Wind Profile, No Batteries, Limit CT, Increase the CT Capital Cost to P85, and Increase the CT Fuel Cost

This sensitivity included increasing both the Avalon CT capital cost to the P85 cost, and increasing the CT fuel cost in the same manner as Scenario 1AEFG. The results of this Expansion Plan are unchanged from Scenario 1AEF (Reference Case). The initial least-cost supply options to meet the Reference Case requirements are BDE Unit 8 and the Avalon CT.

The NPV of Scenario 1AEFGH is $7.0 billion, $0.3 billion more than Scenario 1AEF. The annual emissions for this scenario after the Holyrood TGS is retired are estimated to be 25 kt until the proxy capacity resource option is constructed in 2034, which increases the annual emissions to 35 kt.

5.2.1.1.8 Scenario 1AEFJ: Fixed Wind Profile, No Batteries, Limit CT, and Potential for Clean Electricity Investment Tax Credit

Lastly, a sensitivity was developed that explored the potential benefits that may be derived if a proposed Clean Electricity Investment Tax Credit is implemented. The Government of Canada's 2024 Fall Economic Statement included the proposed provision for the Clean Electricity Investment Tax Credit. If approved, the proposed Clean Electricity Investment Tax Credit could result in a refundable credit equal to 15% of the capital cost of eligible investments, of which BDE Unit 8 and other hydro resource options may be eligible. Therefore, this sensitivity applied a 15% reduction to the total capital cost of eligible options. It is important to note that this investment tax credit is not yet approved by the federal government and would require certain actions by the Government to allow Hydro to be eligible; however, Hydro will look for all avenues to reduce costs, including applying for this tax credit, should it be a possibility. The results of this Expansion Plan are unchanged from Scenario 1AEF (Reference Case). The initial least-cost supply options to meet the Reference Case requirements are BDE Unit 8 and the Avalon CT.

The NPV of Scenario 1AEFJ is $6.4 billion, $0.3 billion less than Scenario 1AEF. The annual emissions for this scenario after the Holyrood TGS is retired are estimated to be 25 kt until the proxy capacity resource option is constructed in 2034, which increases the annual emissions to 35 kt.

5.2.1.2 NPV Comparison

The total Expansion Plan costs presented herein include generation capital costs, fixed and variable O&M[38] costs, and fuel costs. Export market revenue has not been included and does not vary significantly for a given load forecast.[39] 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 were addressed in Section 7.3 of the 2024 Resource Adequacy Plan.[40] The annual costs from the PLEXOS model are translated to a NPV using the weighted average cost of capital ("WACC") to discount future financial impacts to today's value. Because the selected generation 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 5 compares the NPV of the Scenario 1 (Reference Case) sensitivities to help identify the cost impact of each sensitivity that was applied.

[38] Operations and maintenance ("O&M").
[39] 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.
[40] Hydro is exploring whether lower-cost alternatives can be taken to maximize transfer capacity through existing assets, including the implementation of a RAS and/or DLR technology as technically equivalent options to the transmission requirements.

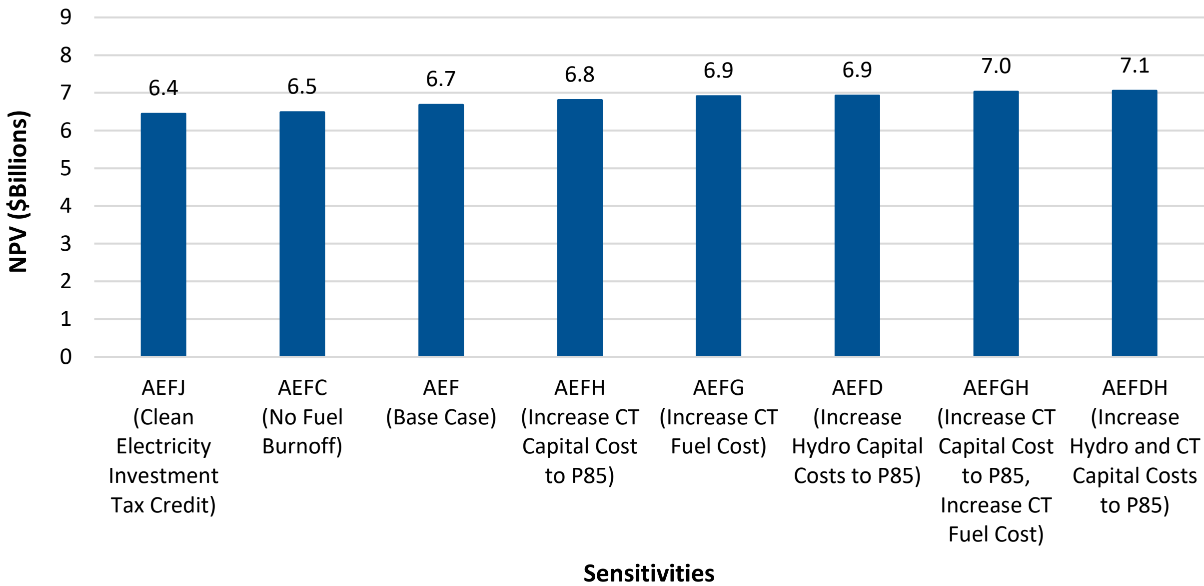

Chart 5: NPV Scenario 1 (Reference Case) Test Sensitivity Comparison[41]

It is important to note that the NPV for Scenario 1AEFC is lower than the Base Case (Scenario 1AEF) because the forced fuel burn-off has been removed. The savings in this scenario compared to other scenarios in this analysis is not due to a reduction in expansion costs but through improved fuel management practices. The initial least-cost supply options to meet the Reference Case requirements in all sensitivities applied to Scenario 1 are BDE Unit 8 and the Avalon CT.

5.2.1.3 Annual Emissions Comparison

Chart 6 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.

[41] All costs are presented in 2024 Canadian dollars.

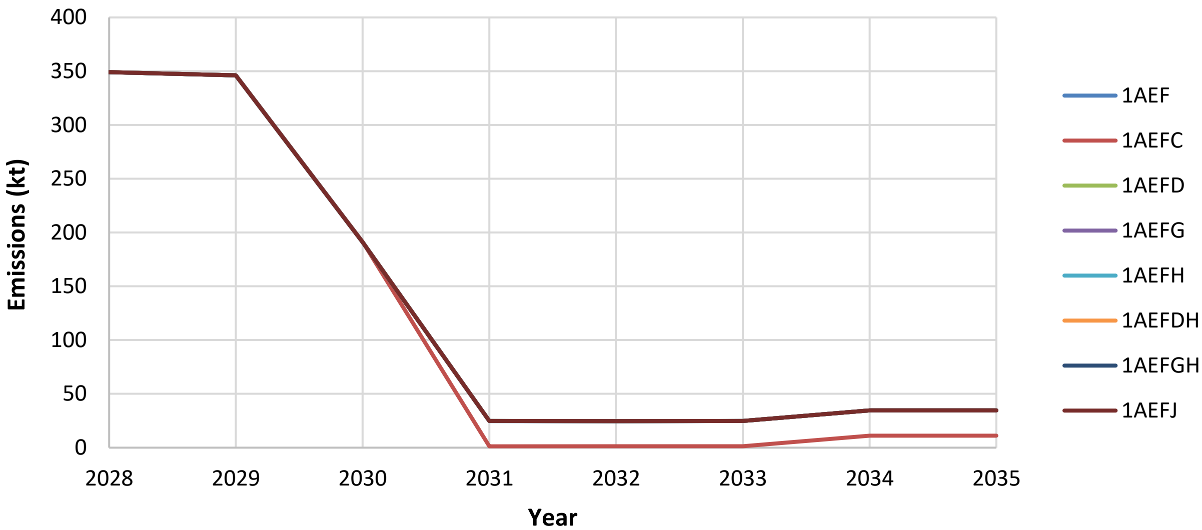

Chart 6: Comparison of Scenario 1 Sensitivities Annual Emissions[42,43]

As Chart 6 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 35 kt which corresponds to all Scenarios that assume an annual fuel burn-off requirement. This is an approximately 90% 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.

5.2.2 Scenario 4: Minimum Investment Required

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 provided in the following sections:

- Resource Requirements (Section 5.2.2.1);
- NPV Comparison (Section 5.2.2.2); and

[42] The full time horizon of the study period was limited to 2028 to 2035 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.
[43] Other than Scenario 1AEFC, all other sensitivities have the same annual emissions.

- Annual Emissions Comparison (Section 5.2.2.3).

5.2.2.1 Resource Requirements

Scenario 4 includes the Slow Decarbonization load forecast, assumes a LIL bipole EqFOR of 1%, and a probabilistic planning criteria of 2.8 LOLH, as summarized in Table 2 in Section 5.1. The results of the Expansion Plan sensitivities are summarized within Table 5 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 5 shows the results for 2030 through 2035, 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.

In all the sensitivities of the Minimum Investment Required scenario analyzed, including escalation of both BDE Unit 8 and Avalon CT to the Authorized Budget (P85), the model does not change the Expansion Plan outcome.

The model shows that the following resources are required to meet the requirements of the Minimum Investment Required:

- In-service date of 2031 for BDE Unit 8;
- In-service date of 2035 for Avalon CT;[44] and
- 400 MW of Wind by 2035.

The Minimum Investment Required Expansion Plan results in approximately an additional 385 MW and 1.4 TWh added to the Island Interconnected System within the next ten years, and the selection

[44] While this satisfies Hydro's probabilistic criteria, it does not satisfy the LIL shortfall scenario and, as a result, Hydro continues to recommend the advancement of a CT as early as possible. Further discussion on the requirement for the CT by 2031 to meet the LIL shortfall criteria, in addition to BDE Unit 8, can be found in Section 6.2.

of both Avalon CT and BDE Unit 8 as the first steps to meet the Minimum Investment Required are common to all scenarios studied.

5.2.2.1.1 Scenario 4AEF: Fixed Wind Profile, No Batteries, and Limit CTs

Scenario 4 (Minimum Investment Required) includes the Slow Decarbonization load forecast, assumes a LIL bipole EqFOR of 1%, and a probabilistic planning criteria of 2.8 LOLH, as summarized in Table 2, Section 5.1. As mentioned previously, sensitivity "AEF" was included as the starting point for the 2025 Build Application analysis. Sensitivity "AEF" considers a fixed wind profile to meet Hydro's firm energy criteria, excludes batteries as a resource option,[45] and limits the number of CTs that can be constructed to one, 150 MW On-Avalon CT in consideration of current diesel fuel supply availability on the Island. The results of this Expansion Plan are summarized in Table 5. All of the Scenario 4 sensitivities produced the same Expansion Plan, and hence this table has not been repeated in the following sections.

Table 5: Scenario 4AEF (Fixed Wind Profile, No Batteries, and Limit CTs)

Resource	Firm Capacity (MW)	Firm Energy (GWh)	2030	2031	2032	2033	2034	2035
BDE Unit 8	154.4	0		1	1	1	1	1
CT	141.6	0						1
Wind	22	350	1	3	3	4	4	4
Firm Capacity (MW)			22	220	220	242	242	384
Firm Energy (GWh)			350	1050	1050	1400	1400	1400

The Expansion Plan for Scenario 4AEF includes BDE Unit 8 in 2031. In the 2024 Resource Adequacy Plan, the CT was selected as being required in 2034. Due to the reduction in demand in the 2024 Slow Decarbonization load forecast, the requirement for the CT to meet Hydro's probabilistic capacity criteria

[45] Based on analysis performed by Hydro as part of the *RRA Study Review*, BESS are emerging as a viable supply solution worthy of further consideration. However, there remain appreciable feasibility concerns surrounding BESS solutions related to capability in emergency scenarios such as an extended outage to the LIL bipole. Given concerns regarding BESS solutions in the event of a LIL shortfall scenario, such solutions were not included as capacity resources in the Minimum Investment Required Expansion Plan (i.e., the recommended Expansion Plan). Additional information can be found in response to PUB-NLH-339 of the *RRA Study Review*. Hydro is committed to further study of battery ELCC to inform the 2026 Resource Adequacy Plan as outlined in response to PUB-NLH-334.

has been delayed by one year, to 2035. Further discussion on the requirement for the CT by 2031 to meet the Shortfall Criteria,[46] in addition to BDE Unit 8, can be found in Section 6.2.

To meet the firm energy criteria, 100 MW of wind is required in 2030, corresponding to the same year that Holyrood TGS is retired. The firm energy requirement escalates to 300 MW of wind in 2031, and further escalates to 400 MW by 2033. 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 4 (Minimum Investment Required). 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.

The total cost, in terms of NPV, of this Expansion Plan is $3.3 billion and the annual emissions after the Holyrood TGS is retired to the end of the planning horizon (2035) are estimated to be 1 kt.

5.2.2.1.2 Scenario 4AEFC: Fixed Wind Profile, No Batteries, Limit CTs, and No Fuel Burn-Off

As described in Section 5.2.2.1.2, a sensitivity was designed to assess the influence of removing the fuel burn-off requirement. The results of this Expansion Plan are unchanged from Scenario 4AEF (Minimum Investment Required). The initial least-cost supply options to meet the Minimum Investment requirements are BDE Unit 8 and the Avalon CT.

By reducing fuel burn-off, the NPV of this sensitivity reduces to $3.2 billion, a slight decrease of $0.1 billion compared to Scenario 4AEF (Fixed Wind, No Batteries, and Limit CT). The annual emissions are estimated to be 1 kt through the study period, once Holyrood TGS is retired.

5.2.2.1.3 Scenario 4AEFD: Fixed Wind Profile, No Batteries, Limits CTs, and Increase Hydro Capital Costs to P85

Another sensitivity was included to reflect the potential for cost overruns of hydro projects. In this sensitivity, the P85 capital cost of BDE Unit 8 was modeled.[47,48] In addition, the percentage increase in

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[46] 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.
[47] In all other Scenarios, unless otherwise stated, the P50 capital cost for BDE Unit 8 is modeled.
[48] In the 2024 Resource Adequacy Plan, a similar sensitivity was included that increased the capital cost of all hydroelectric resource options, including BDE Unit 8, by 50%. Please refer to the 2024 Resource Adequacy Plan, app. C, sec. 6.2.2.1.6.

costs from the BDE Unit 8 P50 capital cost to the P85 capital cost was applied to the capital cost of all hydroelectric options. The results of this Expansion Plan are unchanged from Scenario 4AEF (Minimum Investment Required). The initial least-cost supply options to meet the Minimum Investment requirements are BDE Unit 8 and the Avalon CT.

This scenario has an NPV of $3.4 billion, $0.1 billion more than Scenario 4AEF (Fixed Wind, No Batteries, and Limit CTs). The annual emissions for this scenario after the Holyrood TGS is retired are estimated to be 1 kt, until the CT is required, increasing the annual emissions to 25 kt.

5.2.2.1.4 Scenario 4AEFG: Fixed Wind Profile, No Batteries, Limit CTs, and Increase Fuel Cost

Further testing the CT as a resource option includes increasing the fuel costs in recognition of increasing future demand for diesel fuel in combination with the potential for future supply shortages in Canada.[49] Similar to Scenario 1AEFG, the fuel cost was increased to $2.05/litre and escalated through the study period.[50] The results of this Expansion Plan are unchanged from Scenario 4AEF (Minimum Investment Required). The initial least-cost supply options to meet the Minimum Investment requirements are BDE Unit 8 and the Avalon CT.

The NPV of Scenario 4AEFG is $3.4 billion, a $0.1 billion increase from Scenario 4AEF (Fixed Wind, No Batteries, and Limit CT). The annual emissions are estimated to be 1 kt from 2031 onward until the CT is required, which increases the annual emissions to 25 kt.

5.2.2.1.5 Scenario 4AEFH: Fixed Wind Profile, No Batteries, Limit CTs, and Increase CT Capital Cost to P85

Another sensitivity was completed to explore increasing the CT capital cost to the P85 cost. The results of Scenario 4AEFH Expansion Plan are unchanged from Scenario 4AEF (Minimum Investment Required). The initial least-cost supply options to meet the Minimum Investment requirements are BDE Unit 8 and the Avalon CT.

[49] For more information, please refer to the 2024 Resource Adequacy Plan, app. C, sec. 4.4.1.
[50] The Fuel Market Study is provided in the 2024 Resource Adequacy Plan, app. C, att. 4.

The NPV of Scenario 4AEFH is $3.4 billion, the same as Scenario 4AEF (Fixed Wind, No Batteries, and Limit CT). The annual emissions from 2031 onward are estimated to be 1 kt from 2031 onward until the CT is required, which increases the annual emissions to 25 kt.

5.2.2.1.6 Scenario 4AEFDH: Fixed Wind Profile, No Batteries, Limit CTs, and Increase Hydro and CT Capital Costs to P85

This sensitivity included increasing both the Avalon CT capital cost and the BDE Unit 8 capital cost to the P85 cost. The results of this Expansion Plan are unchanged from Scenario 4AEF (Minimum Investment Required). The initial least-cost supply options to meet the Minimum Investment requirements are BDE Unit 8 and the Avalon CT.

In this scenario the CT continues to be selected in 2035. The NPV of Scenario 4AEFDH is $3.5 billion, $0.2 billion more than Scenario 4AEF. The annual emissions for this scenario after the Holyrood TGS is retired are estimated to be 1 kt until the CT is constructed, which increases the annual emissions to 25 kt.

5.2.2.1.7 Scenario 4AEFGH: Fixed Wind Profile, No Batteries, Limit CT, Increase the CT Capital Cost to P85, and Increase the CT Fuel Cost

This sensitivity included increasing both the CT capital cost to the P85 cost, and increasing the CT fuel cost in the same manner as Scenario 4AEFG. The results of this Expansion Plan are unchanged from Scenario 4AEF (Minimum Investment Required). The initial least-cost supply options to meet the Minimum Investment requirements are BDE Unit 8 and the Avalon CT.

BDE Unit 8 has consistently been selected as the least-cost resource option and an increase in the Avalon CT costs only emphasizes this. The NPV of Scenario 4AEFGH is $3.5 billion, $0.2 billion more than Scenario 4AEF. The annual emissions for this scenario after the Holyrood TGS is retired are estimated to be 1 kt from 2031 onward until the CT is required, which increases the annual emissions to 25 kt.

5.2.2.1.8 Scenario 4AEFJ: Fixed Wind Profile, No Batteries, Limit CT, and Potential for Clean Electricity Investment Tax Credit

Lastly, a sensitivity was developed that explored the potential benefits that may be derived if a proposed Clean Electricity Investment Tax Credit is implemented. The Government of Canada’s 2024 Fall Economic Statement included the proposed provision for the Clean Electricity Investment Tax Credit. If approved, the proposed Clean Electricity Investment Tax Credit could result in a refundable credit equal to 15% of the capital cost of eligible investments, of which BDE Unit 8 and other hydro resource options may be eligible. Therefore, this sensitivity applied a 15% reduction to the total capital cost of eligible options. It is important to note that this investment tax credit is not yet approved by the federal government and would require certain actions by Government to allow Hydro to be eligible; however, Hydro will look for all avenues to reduce costs, including applying for this tax credit, should it be a possibility. The results are unchanged from Scenario 4AEF (Minimum Investment Required). The initial least-cost supply options to meet the Minimum Investment requirements are BDE Unit 8 and the Avalon CT.

The NPV of Scenario 4AEFJ is $3.2 billion, $0.1 billion less than Scenario 4AEF. The annual emissions for this scenario after the Holyrood TGS is retired are estimated to be 1 kt until the CT is required in 2035, which increases the annual emissions to 25 kt.

5.2.2.2 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.[51] Financing costs associated with new capital spending are also not included. The costs of transmission requirements are also not considered in the NPV comparison. 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 the selected generation 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 7 compares the NPV of the Scenario 4 (Minimum Investment Required) sensitivities to help identify the cost impact of each sensitivity that was applied.

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[51] 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.

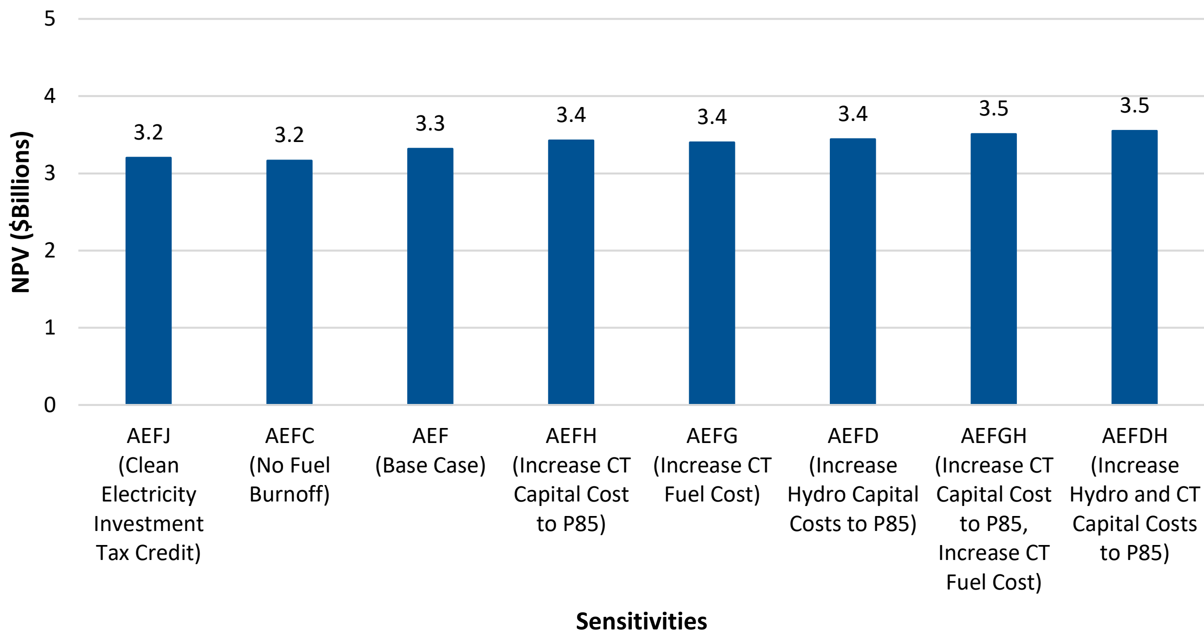

Chart 7: NPV Scenario 4 (Minimum Investment Required) Sensitivity Comparison[52]

The NPV for Scenario 4AEFC is lower than the Base Case (Scenario 4AEF) because the forced fuel burn-off has been removed. The savings in this scenario compared to other scenarios in this analysis are not due to a reduction in expansion costs but through improved fuel management practices. The initial least-cost supply options to meet the Minimum Investment requirements in all sensitivities applied to Scenario 1 are BDE Unit 8 and the Avalon CT.

5.2.2.3 Annual Emissions Comparison

Chart 8 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.

[52] All costs are presented in 2024 Canadian dollars.

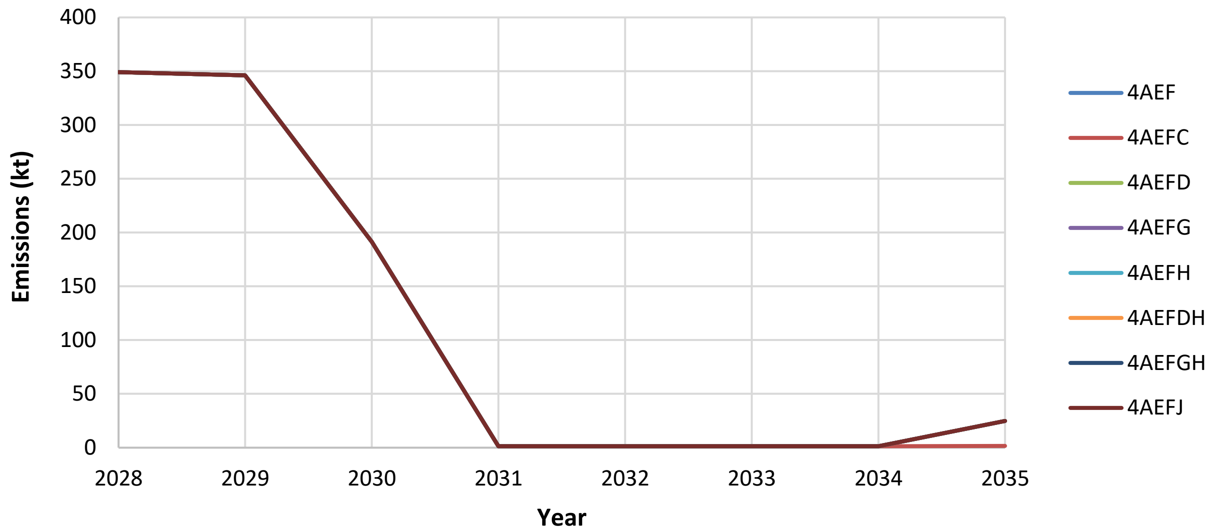

Chart 8: Comparison of Scenario 4 Sensitivities Annual Emissions[53,54]

As Chart 8 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 1 kt. However, once the CT is constructed, the estimated annual emissions is 25 kt. This is an approximately 93% reduction in fuel emissions that may be achieved once the Holyrood TGS is retired. Should system conditions differ from that assumed in this analysis, annual emissions could be more than presented.

6.0 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,[55] the *CER*, and the goal for a net zero GHG emissions economy by 2050. Where possible, Hydro intends to minimize its environmental

[53] The full time horizon of the study period was limited to 2028 to 2035 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.
[54] Other than Scenario 4AEFC, all other sensitivities have the same annual emissions.
[55] Environment and Climate Change Canada ("ECCC").

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.

Each of these analyses is described further in the following sections.

6.1 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 December 2024, the Government of Canada finalized the *CER*,[56] the draft versions of which were key considerations in Hydro's evaluation of potential new sources of generation during the 2024 Resource Adequacy Plan. 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.

Beginning in 2035, the *CER* will place limits on the emissions from most generating units in Canada that use fossil fuels. The *CER* will apply to generating units meeting the following three criteria:

1) Generates electricity using fossil fuels;
2) Has a capacity of 25 MW or greater; and
3) Is connected to an interconnected electricity system.

[56] Environment and Climate Change Canada. (2024). *Powering Canada's Future: Securing jobs, investments, and savings by building more affordable and reliable clean electricity.* Government of Canada. https://www.canada.ca/en/environment-climate-change/news/2024/12/powering-canadas-future-securing-jobs-investments-and-savings-by-building-more-affordable-and-reliable-clean-electricity.html.

A new CT greater than 25 MW in capacity would be subject to the regulations if run on fossil fuels, such as the new Avalon CT included in the 2025 Build Application.

The *CER* recognizes that certain jurisdictions may be required to maintain fossil-fuel-utilizing facilities as part of their fleet for various reasons. The *CER* imposes an emission limit approach, with a unit-specific annual emissions limit, calculated as shown in Figure 3.

$$\mathbf{C \times I_{el} \times 8760 \times 0.001}$$

where

C is the unit's electricity generation capacity for the calendar year; and

I_{el} is the emissions intensity applicable to the calendar year and is

(a) 65 tonnes of CO_2 emissions per GWh for the 2035 to 2049 calendar years, and

(b) 0 tonnes of CO_2 emissions per GWh for the 2050 and subsequent calendar years.

Figure 3: Annual Limit on Emissions Calculation

The emissions limit for a new 150 MW CT (or three units adding up to the same total capacity) would equate to 85.4 kt of CO_2 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 130 GWh[57] of generation, or 890 hours (37 full days) of annual generation at maximum capacity (i.e., a 10% 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. 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 *CER*. A number of flexibility mechanisms such as transferable compliance credits, are also part of the *CER*, which would give Hydro additional flexibility to use thermal generating assets to maintain a reliable system while maintaining compliance with the *CER*.

[57] Based on a heat rate of 9,167 GJ/GWh, 38.5 MJ/L energy content of diesel fuel, and 2,677 g CO_2/L.

6.2 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 should be expanded to consider 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. 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[58] 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[59] 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.[60] 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.

[58] 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.
[59] The probabilistic analysis considers 2,400 random combinations of weather-driven loads, unit outage profiles, and renewable generation.
[60] Please refer to the 2024 Resource Adequacy Plan, app. B, sec. 5.1.5.

- **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 on-Island transmission constraints but generation (supply) constraints only. A summary of the on-Island transmission constraints during a LIL bipole outage is provided in Section 6.3.[61]

After completing its shortfall analysis, Hydro is continuing to recommend advancing the Avalon CT from 2035 to 2031, in order to ensure the Island Interconnected System will have sufficient generating capacity to limit the loss of load to a manageable level in the case of a LIL shortfall event.[62]

The shortfall analysis was completed for the following combinations of Island load forecasts and Expansion Plans:

- **Combination 1:** Slow Decarbonization load forecast and Scenario 4AEF (Minimum Investment Required) Expansion Plan;
- **Combination 2:** Slow Decarbonization load forecast and Scenario 4AEF (Minimum Investment Required) Expansion Plan with the Avalon CT advanced from 2035 to 2031 (referred to as Scenario 4 AEF(ADV) (Minimum Investment Required) going forward); and
- **Combination 3:** 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;

[61] Detailed analysis can be found in the 2024 Resource Adequacy Plan, app. C, sec. 7.3.
[62] 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.

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.

6.2.1 Combination 1

Combination 1 assumes Slow Decarbonization with Scenario 4AEF (Minimum Investment Required) Expansion Plan. As Chart 9 demonstrates, under the Average Case (green line), unserved energy would be expected to occur for 142 hours within the six-week period, representing approximately 10 GWh of energy shortfall. The highest anticipated peak shortfall is estimated to be 256 MW. Under the Severe Case (blue line), the peak shortfall is estimated to be 358 MW with 351 hours of unserved energy over the period, totalling 35 GWh of energy shortfall.

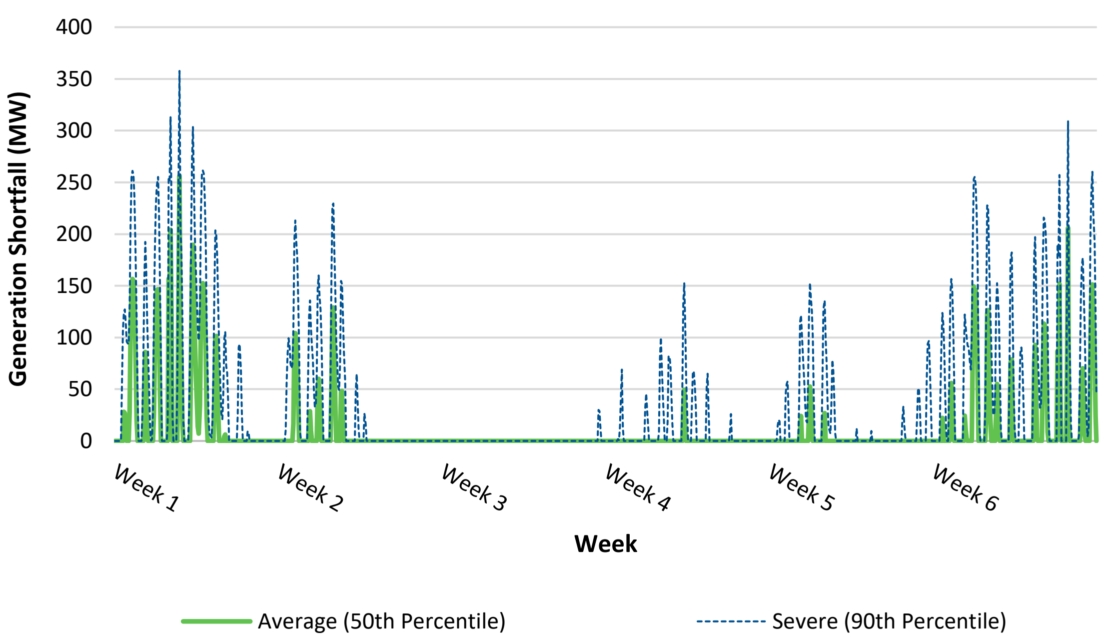

Chart 9: Shortfall over Six Weeks (Combination 1: Slow Decarbonization Load, Scenario 4AEF (Minimum Investment Required) Expansion Plan)

Chart 10 shows the estimated unserved energy on the peak day in the 2032 reference year.

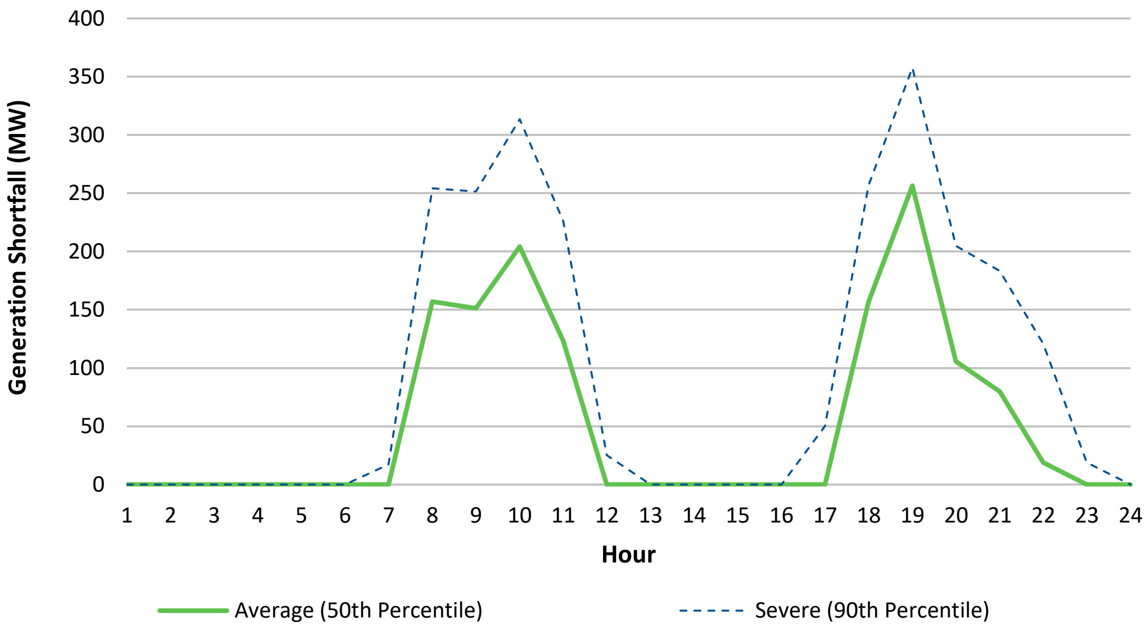

Chart 10: Shortfall on Peak Day (Combination 1: Slow Decarbonization Load, Scenario 4AEF (Minimum Investment Required) Expansion Plan)

Chart 11 depicts the shortfall duration curve for Combination 1 (Slow Decarbonization, Scenario 4AEF (Minimum Investment Required) Expansion Plan). In the Average Case (green line), a supply shortfall of 100 MW[63] or greater is experienced approximately 4% of the time. In the Severe Case (blue line), a supply shortfall of 100 MW or higher is expected approximately 14% of the time.

[63] Newfoundland Power was able to rotate 100 MW during the 2014 loss of load event.

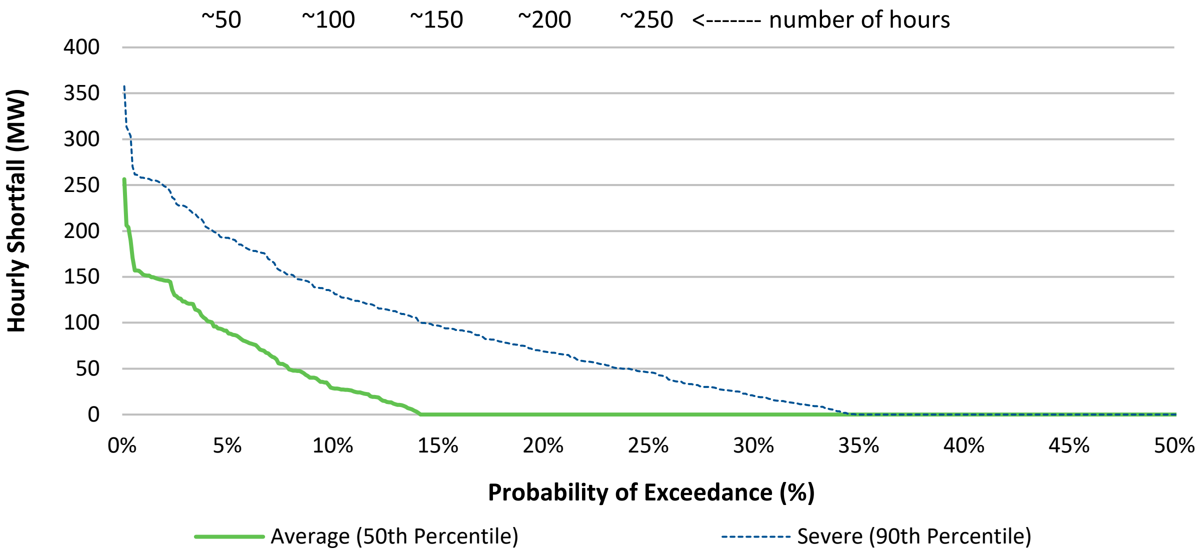

Chart 11: Shortfall Duration Curve (Combination 1: Slow Decarbonization Load, Scenario 4AEF (Minimum Investment Required) Expansion Plan)

For ease of reference, Table 6 summarizes the results for Combination 1 described above.

Table 6: Summary of Combination 1 Shortfall Statistics

	Average Case	Severe Case
Hours of shortfall	142	351
Total energy shortfall (GWh)	10	35
Peak shortfall (MW)	256	358
% of time shortfall > 100 MW	4%	14%

6.2.2 Combination 2

Combination 2 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 supply shortfall that could be expected if the CT resource option was advanced by a few years. As Chart 12 demonstrates, under the Average Case (green line), unserved energy would be expected to occur in 24 hours over the six-week period, representing 1 GWh of energy shortfall. The highest anticipated peak shortfall is estimated to be 124 MW; however, 99% of the time the peak shortfall is expected to be below 100 MW.[64] Under the Severe Case (blue line), the peak shortfall is estimated to be 232 MW with 102 hours of unserved energy over the period, representing 7 GWh of energy shortfall.

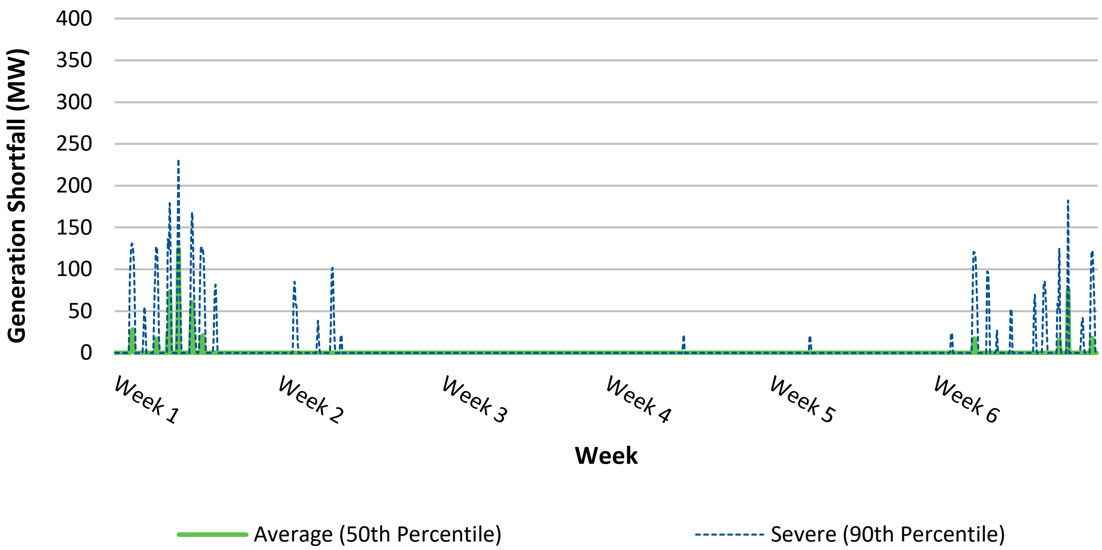

Chart 12: Shortfall over Six Weeks (Combination 2: Slow Decarbonization Case Load, Scenario 4AEF(ADV) (Minimum Investment Required) Expansion Plan)

[64] This combination was represented as Combination 3 in the 2024 Resource Adequacy Plan, app. C, sec. 7.2.3. The highest anticipated shortfall was estimated to be 85 MW in the Average Case. As the energy requirements identified in the 2023 Load Forecast were less than the energy requirements identified in the 2024 Load Forecast, this led to a reduction of one 100 MW wind farm that is required in 2032. As each 100 MW wind farm has an assumed capacity contribution of 22 MW, the result is less capacity that is available to mitigate a potential shortfall situation in 2032. In addition, customer demand represented in the 2024 Load Forecast is slightly higher in 2032 compared to the 2023 Load Forecast, which compounds the shortfall amount that is represented in this updated analysis. This only further strengthens the need for capacity on the Island Interconnected System.

Chart 13 shows the estimated unserved energy on the peak day in the 2032 reference year.

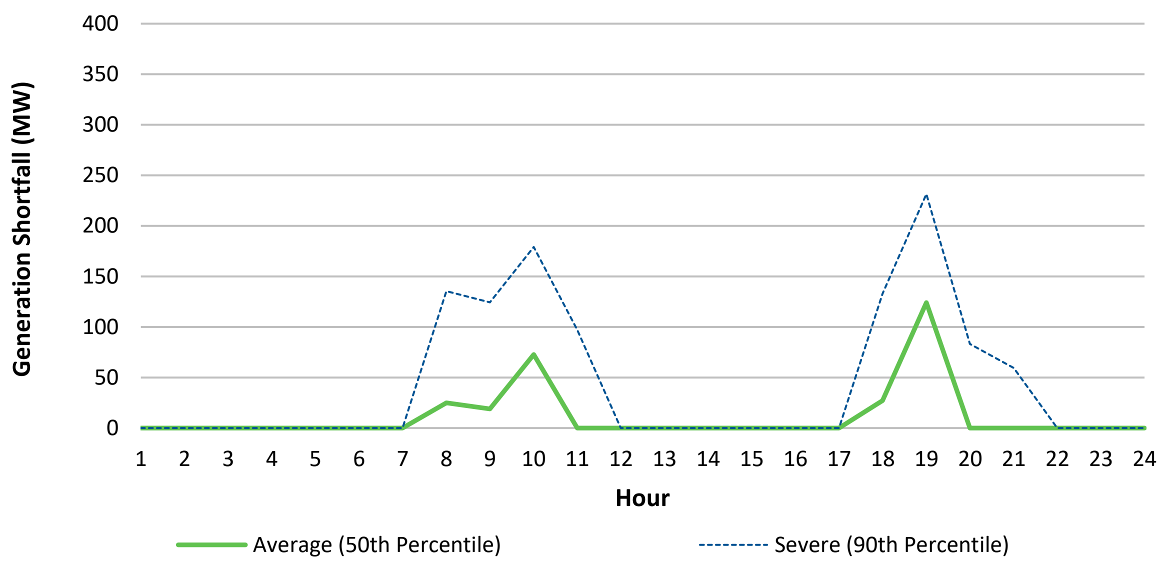

Chart 13: Shortfall on Peak Day (Combination 2: Slow Decarbonization Case Load, Scenario 4AEF(ADV) (Minimum Investment Required) Expansion Plan)

Chart 14 depicts the shortfall duration curve for Combination 2 (Slow Decarbonization Load, Scenario 4AEF (ADV) (Minimum Investment Required) Expansion Plan). In the Average Case (green line), a supply shortfall of over 100 MW[65] 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 3% of the time.

[65] Newfoundland Power Inc. was able to rotate 100 MW during the 2014 loss of load event.

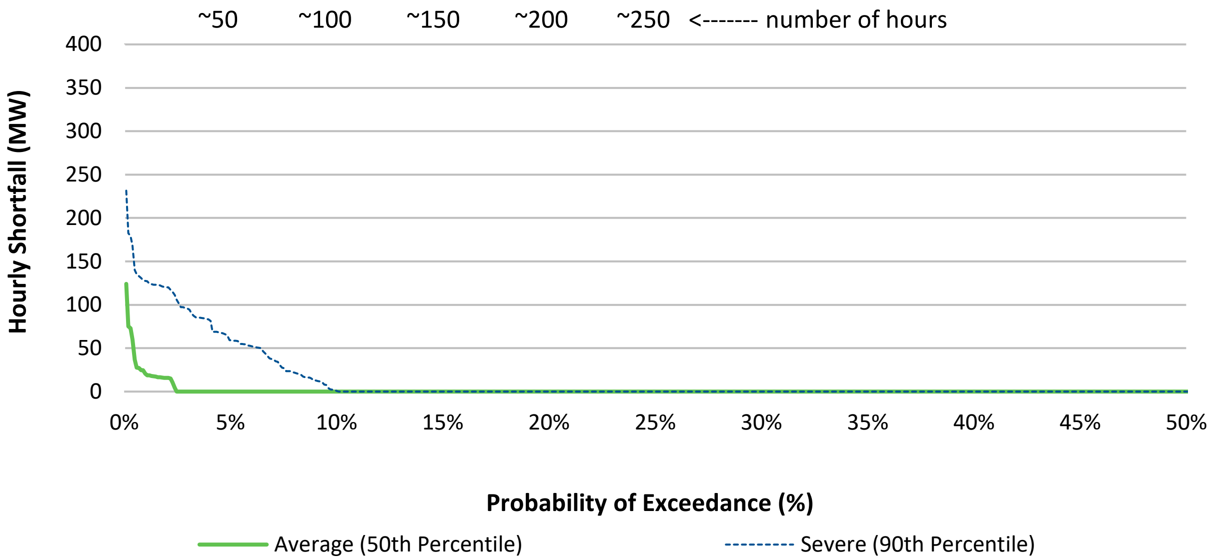

Chart 14: Shortfall Duration Curve (Combination 2: Slow Decarbonization Case Load, Scenario 4AEF(ADV) (Minimum Investment Required) Expansion Plan)

For ease of reference, Table 7 summarizes the results for Combination 2 described above.

Table 7: Summary of Combination 2 Shortfall Statistics

	Average Case	Severe Case
Hours of shortfall	24	102
Total energy shortfall (GWh)	1	7
Peak shortfall (MW)	124	232
% of time shortfall > 100 MW	0.1%	3%

Combination 2 supports the advancement of the in-service date of the Avalon CT to the earliest possible timeframe; however, it is important to note that the 150 MW Avalon CT alone will not enable the retirement of all three units at Holyrood TGS.

6.2.3 Combination 3

Combination 3 assumes the Reference Case load forecast with Scenario 4AEF(ADV) (Minimum Investment Required) Expansion Plan. 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 15 demonstrates, under the Average Case (green line), unserved energy would be expected to occur in 45 hours over the six-week period, representing 2 GWh of energy shortfall. The highest anticipated peak shortfall is estimated to be 158 MW. Under the Severe Case (blue line), the peak shortfall is estimated to be 267 MW with 162 hours of unserved energy over the period, representing 12 GWh of energy shortfall.

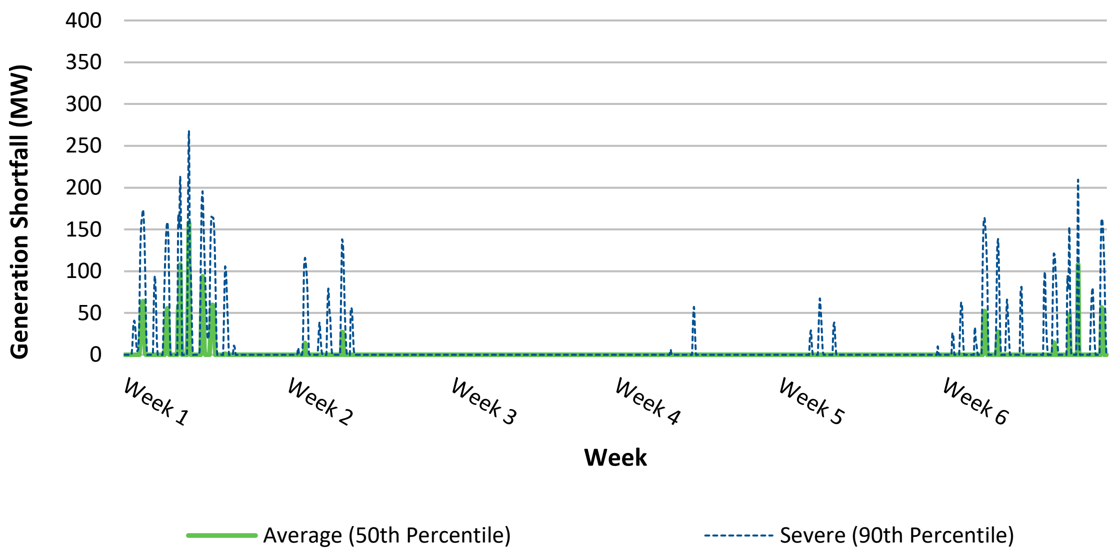

Chart 15: **Shortfall over Six Weeks (Combination 3: Reference Case Load, Scenario 4AEF(ADV) (Minimum Investment Required) Expansion Plan)**

Chart 16 shows the estimated unserved energy on the peak day in the 2032 reference year.

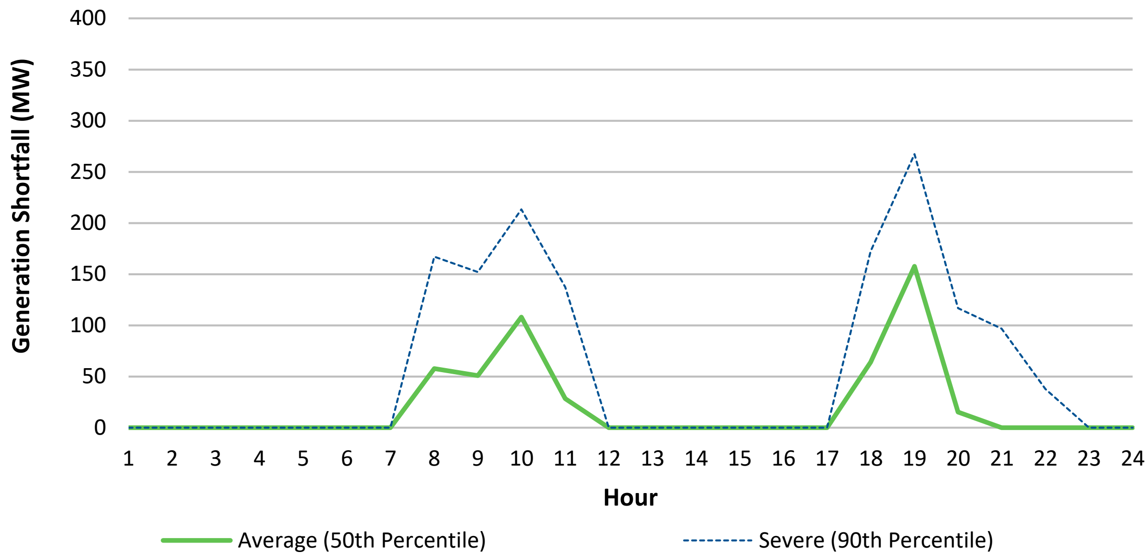

Chart 16: Shortfall on Peak Day (Combination 3: Reference Case Load, Scenario 4AEF(ADV) (Minimum Investment Required) Expansion Plan)

Chart 17 depicts the shortfall duration curve for Combination 3 (Reference Load, Scenario 4AEF(ADV) Expansion Plan). In the Average Case (green line), a supply shortfall of over 100 MW[66] occurs in three hours over the six-week period. In the Severe Case (blue line), a supply shortfall of 100 MW or higher is expected approximately 5% of the time.

[66] Newfoundland Power was able to rotate 100 MW during the 2014 loss of load event.

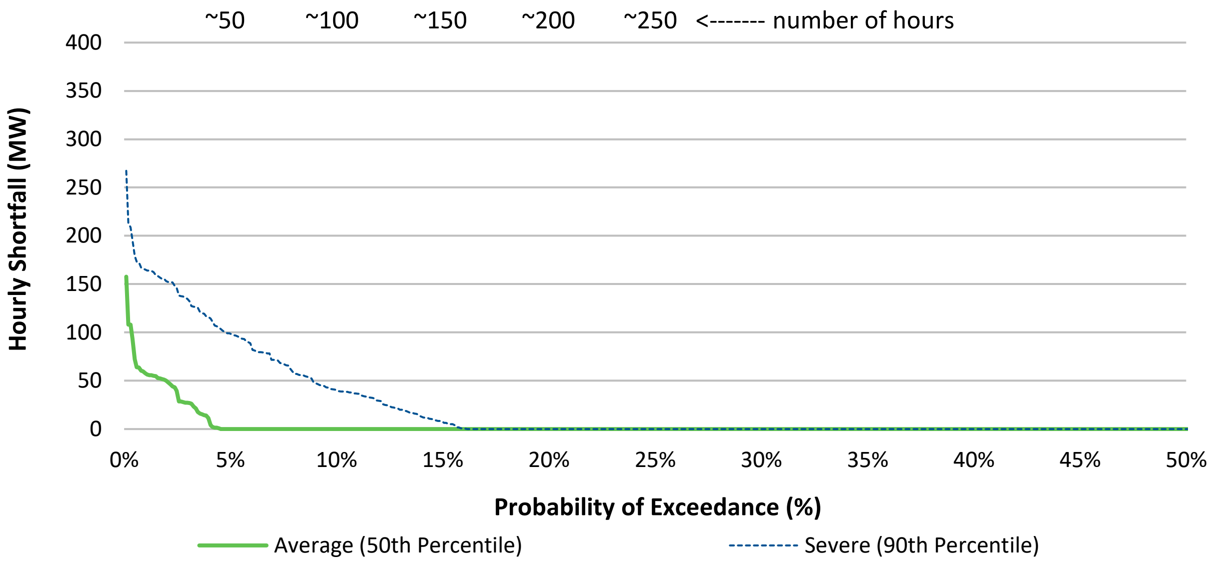

Chart 17: Shortfall Duration Curve (Combination 3: Reference Case Load, Scenario 4AEF(ADV) (Minimum Investment Required) Expansion Plan)

1 For ease of reference, Table 8 summarizes the results described for Combination 3 above.

Table 8: Summary of Combination 3 Shortfall Statistics

	Average Case	Severe Case
Hours of shortfall	45	162
Total energy shortfall (GWh)	2	12
Peak shortfall (MW)	158	267
% of time shortfall > 100 MW	0.3%	5%

Table 9 and Table 10 illustrate the comparison of the three combinations under Average and Severe conditions, respectively.

Table 9: Comparison of Shortfall Statistics under Average Case

	Combination 1	Combination 2	Combination 3
Load Scenario	Slow Decarbonization	Slow Decarbonization	Reference Case
Expansion Plan Scenario	4AEF	4AEF(ADV)	4AEF(ADV)
Hours of shortfall	142	24	45
Total energy shortfall (GWh)	10	1	2
Peak shortfall (MW)	256	124	158
% of time shortfall > 100 MW	4%	0.1%	0.3%

Table 10: Comparison of Shortfall Statistics under Severe Case

	Combination 1	Combination 2	Combination 3
Load Scenario	Slow Decarbonization	Slow Decarbonization	Reference Case
Expansion Plan Scenario	4AEF	4AEF(ADV)	4AEF(ADV)
Hours of shortfall	351	102	162
Total energy shortfall (GWh)	35	7	12
Peak shortfall (MW)	358	232	267
% of time shortfall > 100 MW	14%	3%	5%

In order to ensure the Island Interconnected System will have sufficient generating capacity to limit the loss of load to a previously demonstrated level in the case of a LIL shortfall event,[67] advancing the Avalon CT from 2035 to 2031 is required, as demonstrated in Combination 2. Should the reference case load forecast materialize, as demonstrated in Combination 3, there is a risk of increased shortfall as load continues to grow. However, Hydro is actively planning for the Reference Case requirements and will present the Reference Case Expansion Plan in the 2026 Resource Adequacy Plan.

6.3 The Expansion Plan and On-Avalon Transmission Constraints

Following the transition from generation to synchronous condenser operations at the Holyrood TGS and the Hardwoods GT, the Bay d'Espoir to Soldiers Pond transmission system must supply the majority of

[67] 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.

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.[68]

A simplified diagram of the Bay d'Espoir to Soldiers Pond 230 kV transmission system is provided in Figure 4, which includes reference to terminal stations in Sunnyside, Come By Chance, Western Avalon, and Long Harbour.

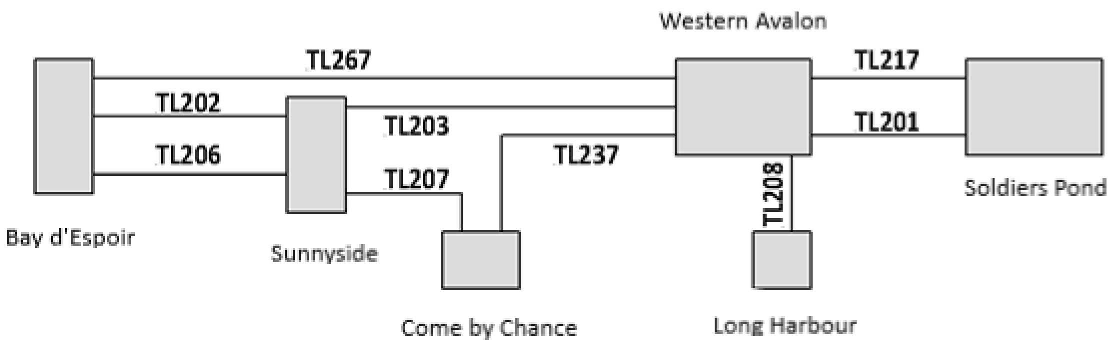

Figure 4: Bay d'Espoir to Soldiers Pond 230 kV Transmission System

As detailed in the 2024 Resource Adequacy Plan, Hydro engaged TransGrid Solutions ("TransGrid") to complete a study[69] to determine the Bay d'Espoir to Soldiers Pond transmission constraints during a LIL bipole outage.[70] The TransGrid Study also presented a series of potential capital transmission upgrade options that could alleviate these constraints to facilitate new Off-Avalon generation.[71]

Upon the retirement of the Holyrood TGS and Hardwoods GT on the Avalon, appreciable transmission bottlenecks are expected 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 will be required to reduce the

[68] 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.
[69] "Avalon Supply (Transmission) Study – Overview," Newfoundland and Labrador Hydro, October 31, 2023.
[70] 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.
[71] The results of this study are detailed in the 2024 Resource Adequacy Plan, app. C, sec. 7.3.

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 reliably served.

The analysis by TransGrid 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. This option is the least-cost option to reliably meet Island demand in combination with the Expansion Plans applied during a LIL bipole outage to keep Avalon load shed requirements below 100 MW.[72]

As mentioned in the 2024 Resource Adequacy Plan, Hydro is exploring alternative steps to maximize transfer capacity through existing assets, including the implementation of a RAS and/or DLR technology. These alternatives if proven, are technically equivalent to the Option 4 transmission upgrades. A 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 each 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.

Hydro is actively evaluating DLR technologies for use on thermally-constrained transmission lines, beginning with TL201. Once a 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. Additionally, Hydro is currently working with TransGrid to perform a study to determine if a RAS is a technically viable solution to increase the transfer limits from Bay d'Espoir to Soldiers Pond. That study is scheduled to be completed by the end of the second quarter of 2025.

[72] Newfoundland Power was able to rotate 100 MW during the 2014 loss of load event.

7.0 Recommended Expansion Plan

Hydro's analysis confirms that the recommendations within the 2024 Resource Adequacy Plan remain the least-cost options. The recommended Expansion Plan remains Scenario 4AEF(ADV) (Minimum Investment Required), which is summarized in Table 11. This Expansion Plan includes BDE Unit 8 and the Avalon CT coming into service in 2031 and up to 400 MW of wind energy by 2033 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 11: Hydro's Recommended Expansion Plan

Resource	Firm Capacity (MW)	Firm Energy (GWh)	2030	2031	2032	2033	2034	2035
BDE Unit 8	154.4	0		1	1	1	1	1
CT	141.6	0		1	1	1	1	1
Wind	22	350	1	3	3	4	4	4
Firm Capacity (MW)			22	362	362	384	384	384
Firm Energy (GWh)			350	1050	1050	1400	1400	1400

The NPV of the Recommended Expansion Plan that meets all of Hydro's established resource planning criteria as outlined in Section 1.0 is $3.5 billion; $0.2 billion more than Scenario 4AEF. The annual emissions for this scenario after the Holyrood TGS is retired are estimated to be 25 kt.

Taking into account the slight reductions in both demand and energy reflected in the 2024 Load Forecast, the updated analysis presented in this report continues to justify the requirement for both BDE Unit 8 and the Avalon CT as the least-cost resource options to meet the reliability requirements of the Island Interconnected System, and therefore supports this build application.

The recommended Expansion Plan achieves the following:

- Meets the load growth considered in the Island Interconnected System 2024 Slow Decarbonization load forecast;
- Meets all prescribed planning criteria considering the 2024 Slow Decarbonization load forecast and a highly reliable LIL (1% LIL bipole EqFOR);

- Meets Hydro's firm energy criteria for the 2024 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;[73]
- Includes an On-Avalon unit with synchronous condenser 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 supply availability on the Island by limiting new CTs as a resource option to a total of 150 MW;
- Helps reduce the reliance on aging thermal assets by enabling the retirement of these assets;
- BDE 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 final *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;
- Aligns with public engagement feedback that showed that residents prioritize least-cost, and therefore lowest impact on rates, compared to increased reliability and clean resource options.[74]
- 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%; and
- Is agnostic to the current Canadian political and geopolitical environment.

[73] As mentioned in Section 6.3, Hydro is actively working to reduce the identified least-cost transmission upgrade through the implementation of a RAS and/or DLR.
[74] Please refer to the 2024 Resource Adequacy Plan, 2024 Resource Plan Overview, sec. 3.3, p. 22.

8.0 Conclusion

In the 2024 Resource Adequacy Plan, Hydro recommended its Minimum Investment Required Expansion Plan (Scenario 4AEF(ADV).1) as a first step to progress planning for the Reference Case (Scenario 1AEF). As the analysis completed for the 2024 Resource Adequacy Plan was based on the 2023 Load Forecast, Hydro felt it prudent to update the expansion plan analysis with the 2024 Load Forecast update to demonstrate that the need for additional energy and capacity remains. In addition, with both the Avalon CT and BDE Unit 8 Class 3 cost estimate, the expansion plan analysis was re-run to demonstrate that these resource options remain least cost.

Advancing the second capacity resource by a few years to 2031 continues to have 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 are to reduce the reliance on aging thermal assets, reduce costs associated with maintaining and operating these assets, and to support the least-cost On-Avalon transmission upgrade.

Resource planning is an iterative process; Hydro is planning to complete the next update to its Resource Adequacy Plan in 2026. At present, there are alternatives to satisfy the incremental load growth between the Minimum Investment Required and the Reference Case and Hydro is taking the appropriate actions to be ready to expedite this additional supply. Regardless, the resource options put forward for approval in the 2025 Build Application represent the first significant step to meeting the capacity requirements of the Province no matter which load forecast scenario unfolds.

Appendix A

2024 Island Interconnected System Load Forecast Report

2024 Island Interconnected System Load Forecast Report

Executive Summary

Newfoundland and Labrador Hydro ("Hydro") annually develops a Reference Case forecast 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 resultant load forecast is a critical primary input to Hydro's overall planning, budgeting, and operating activities. The 2024 Load Forecast was produced in the third quarter of 2024; it covers the period from 2024 through 2035.

Overall, the 2024 Load Forecast is showing growth across the provincial system stemming from several factors including:

- The recent increase in population and related home construction, as indicated by the Government of Newfoundland and Labrador ("Government") forecasts;
- Ongoing electrification[1] activities, primarily resulting from actions taken by the provincial and federal governments to mitigate climate change; electric vehicle ("EV") adoption rates, where possible data on these rates is provided through expert input from third parties such as Dunsky Energy + Climate Advisors ("Dunsky"); and
- Existing Industrial customers' firm requests for expansion and/or decarbonization of their operations.

Hydro previously engaged Daymark Energy Advisors ("Daymark") to provide a third-party independent assessment of the strength of Hydro's load forecasting process, including a review of the underlying methodologies used to produce the 2023 Load Forecast and the accuracy of Hydro's historical forecasts.[2] 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.

[1] Electrification is decarbonization that results in replacing processes or technologies that use fossil fuels with an electrically powered equivalent.
[2] "Long-Term Load Forecast Report – 2023," Newfoundland and Labrador Hydro, March 28, 2024.

Historically, for years one through ten of the load forecast, Hydro's forecast accuracy is within the industry norm.[3] As the time horizon in any forecast increases, the level of error is expected to increase, which supports Hydro's use of alternative scenarios to support system planning assessments.

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 model input data and the relationships estimated in the model. This enables sound decision-making by demonstrating the resiliency of plans against a range of input considerations, allowing for increased certainty when making recommendations. From a load forecast perspective, this process requires the establishment of an appropriate Reference Case. The Reference Case reflects the expected or most likely future scenario based on current information, as well as the analysis of several scenarios, which captures the breadth of potential future outcomes, highlighting the sensitivity of the load forecast to changes in key drivers.

To reflect the potential for variability in the model input data and the relationships estimated in the load forecast, Hydro develops scenarios to capture a broad variation from the Reference Case. Developed scenarios tend to focus on possible alternate future outcomes for macroeconomic drivers of the load forecast and government policies. Examples can include decarbonization, population growth, and industrial expansion or contraction. By developing alternative scenarios, Hydro can assess the sensitivity of its expectations with respect to demand and energy requirements to changes in macroeconomic conditions and validate the robustness of its resource planning activities against the same. This methodology enables Hydro to better manage the inherent uncertainty in forecasting demand and energy requirements during a period of significant industry change that could impact resource planning analyses.

Although a range of load forecasts were developed independently for the Island Interconnected System and the Labrador Interconnected System, for this report Hydro has only included the Island

[3] Hydro assesses the accuracy of its forecasts using the mean absolute percent error with respect to Newfoundland Power Inc. ("Newfoundland Power") domestic customer sales and general service sales. Newfoundland Power requirements represented 80% of the 2023 Island Interconnected System requirements, exclusive of transmission losses and station service.

Interconnected System load forecast as it relates to the 2025 Build Application. Consistent with the forecasts used in the 2024 Resource Adequacy Plan, three forecasts were developed to reflect the range of forecasted Island Interconnected System load requirements, as summarized in Figure 1.

Figure 1: Island Interconnected System Forecast Scenarios

- **Slow Decarbonization Path Scenario ("Slow Decarbonization"):** Considers more moderate decarbonization efforts and electrification of the transportation sector, lower population and housing starts, and current industrial demand, 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, and anticipated electrification of the transportation sector. Also included is a slight increase in industrial growth and a near-term increase in population and housing starts; and
- **Accelerated Decarbonization Path Scenario ("Accelerated Decarbonization"):** Assumes accelerated decarbonization and electrification of the transportation sector. Economic indicators are consistent with the Reference Case and an increase in industrial demand is modelled. This results in a higher load forecast as compared to the Reference Case.

Hydro's recommended Expansion Plan within the 2024 Resource Adequacy Plan, referred to as the Minimum Investment Required Expansion Plan, includes the Slow Decarbonization load forecast. The capacity resource options identified in the Minimum Investment Required Expansion Plan, Bay d'Espoir Unit 8, and a 150 MW Avalon Combustion Turbine, have both been put forth in the 2025 Build Application. While the 2024 Resource Adequacy Plan recommends to build for the Slow Decarbonization load forecast, the most likely forecast scenario remains the Reference Case load forecast. The next update to the Reliability and Resource Adequacy Study, the 2026 Resource Adequacy Plan, will include a recommended expansion plan to meet the Reference Case load forecast. As a result, this report will focus primarily on the Slow Decarbonization and Reference Case load forecast scenarios.

For reference, Chart 1 compares the 2024 and the 2023 Slow Decarbonization and Reference Case load forecast scenarios.

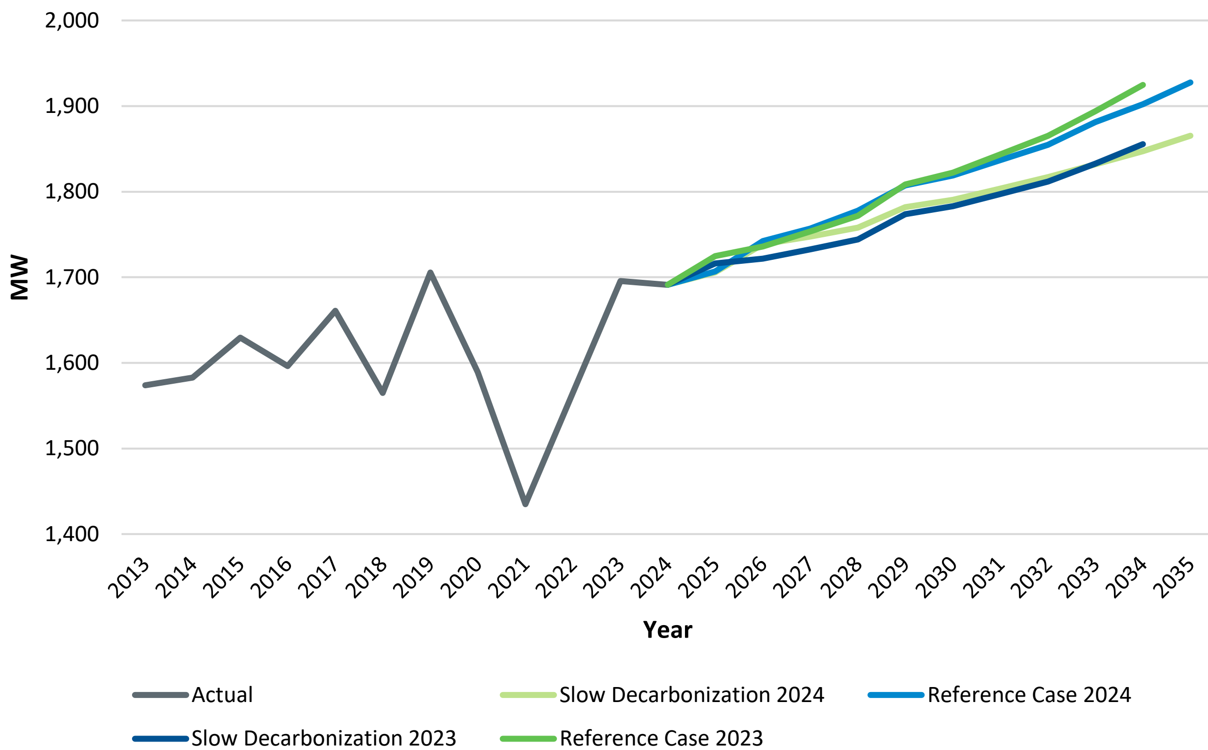

Chart 1: Island Interconnected System Annual Customer Coincident Demand Requirements Comparisons[4,5,6]

The 2024 Reference Case load forecast reflects stability in government policies, incentives, and programs for decarbonization and electrification during the past year. The province continues to see economic growth, an increase in population and housing starts, consistent conversions from oil to

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[4] The Island Interconnected System annual customer coincident demand is reflective of the total Island Interconnected System demand less transmission losses and station service load.
[5] Historical values are not weather normalized.
[6] The significant decline in demand in 2020 and 2021 was due to the effects of the COVID-19 pandemic.

electric, and an increase but steady adoption of EVs. Industrial load continues to increase, primarily attributable to an increase in mining load.

The 2024 Slow Decarbonization load forecast scenario also reflects stability in Government incentives and policies for decarbonization. This scenario continues to consider slower economic activity, slower population growth, and lower housing starts compared to the Reference Case load forecast. This scenario also reflects a slower decarbonization impact, lower oil-to-electric conversions, and a slower adoption of EVs. There are no increases in industrial activity, and current customers are maintained at their existing operating levels.

The resulting interconnected customer electricity demand requirements developed for the Island Interconnected System are presented in Chart 2.

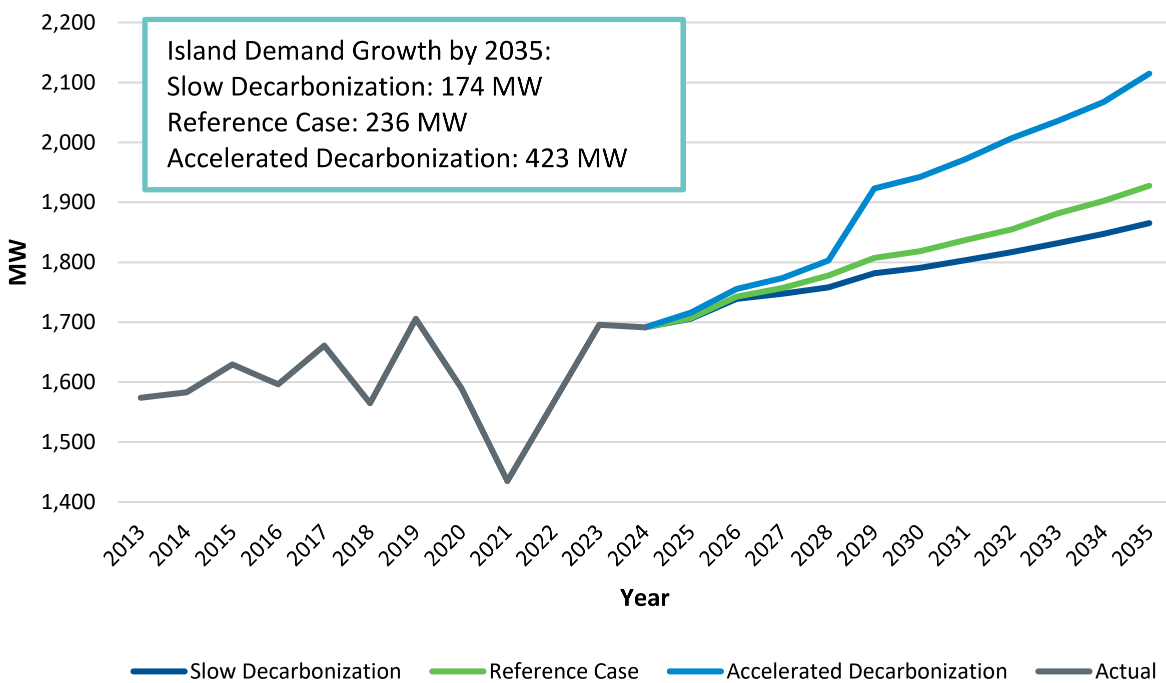

Chart 2: Island Interconnected System Annual Customer Coincident Demand Requirements[7,8,9]

[7] The Island Interconnected System annual customer coincident demand is reflective of the total Island Interconnected System demand less transmission losses and station service load.
[8] Historical values are not weather normalized.
[9] The significant decline in demand in 2020 and 2021 was due to the effects of the COVID-19 pandemic.

The results of the three long-term planning forecast scenarios for the Island Interconnected System project overall load growth for the Island in every scenario across the forecast horizon. The compound annual growth rate[10] ranges from 0.8% in the Slow Decarbonization scenario to 1.9% in the Accelerated Decarbonization scenario. Compared to the 2023 Island Interconnected System forecast, the compound annual growth rate ranged from 0.8% in the Slow Decarbonization scenario to 1.8% in the Accelerated Decarbonization scenario. Therefore, there is an immaterial difference between the compound annual growth between the 2023 and 2024 Load Forecasts.

[10] The compound annual growth rates are based on the forecast load increases from 2024 to 2035.

Contents

List of Attachments

1.0 Introduction

Each year Hydro generates independent load forecasts for the Island and Labrador Interconnected Systems. These forecasts are then used company-wide as the basis for many of Hydro's key business activities, including general rate applications, financial budgeting and forecasting, transmission planning analyses, rate analyses, long-term financial planning, and reliability and resource adequacy assessments.[11]

Hydro is filing the 2024 Island Interconnected System Load Forecast Report with the 2025 Build Application to reflect the most recent view of inputs and economic conditions for the province of Newfoundland and Labrador and to confirm that there is minimal change compared to the 2023 Island Interconnected System load forecast.

To facilitate an increased understanding of the load forecast that formed the basis of the Expansion Plan analysis included in Hydro's 2025 Build Application, this document is intended to provide:

- An overview of Hydro's load forecast philosophy;
- A description of the development of and methodology behind Hydro's load forecast;
- A description of the inputs used to generate the load forecast;
- A summary of Hydro's 2024 Load Forecast results;
- A listing of underlying assumptions for each of Hydro's load forecast scenarios; and
- A discussion of key drivers that influence the outcomes of the load forecast.

2.0 Load Forecast Philosophy

The purpose of load forecasting is to project electric power demand and energy requirements for future periods.[12] The objective of the load forecast process is to characterize and understand the range of possible system demand and energy requirements arising from the inherent uncertainty in the load forecast model inputs, to ensure that Hydro is prepared to serve its customers' needs in the near and

[11] Hydro also produces a forecast for the Isolated System and Labrador Interconnected System; however, this report focuses on the forecasts for the Island Interconnected System only.
[12] Demand is the rate at which electric energy is delivered to or by a system, generally expressed in kilowatts or megawatts, at a given instant or averaged over any designated interval of time.

long term. As a result, the load forecast is a key input to the resource planning process, which recommends what resources should be made available to meet projected demand within the province, consistent with applied reliability standards.

As is generally the case in utility system planning, Hydro uses the Reference Case plus alternative scenarios approach to its load forecast development. The Reference Case is developed to represent Hydro's expectation of the demand and energy requirements that would materialize based on the use of baseline expectations for economic growth and existing government policies and programs. Alternatives to the Reference Case are developed to determine the sensitivity of system requirements to changes in key inputs, both in terms of magnitude of change and timing of requirements.

Consideration of a range of alternatives is a critical component of Hydro's planning activities as it allows for the impact of uncertainty in input parameters on the overall forecast. This enables Hydro and its stakeholders to understand the impact of key parameters like policy adoption rates and differing economic conditions when assessing options and timing of resource additions to meet future customer requirements.

3.0 Load Forecast Methodology

For the Island Interconnected System, the load forecast is segmented into utility load (i.e., Domestic and General Service loads of Newfoundland Power and Hydro) and Industrial load.

The load forecast process for the Island Interconnected System translates the long-term economic outlook and energy price forecast for the Island into corresponding utility demand and energy requirements for the electric power systems.

The forecast process also involves the development and analysis of potential new loads associated with electrification (e.g., EV adoption and conversions of heating systems to electric heat).

For Hydro's large Industrial customers, direct input from those customers forms the basis for Hydro's forecast of their firm electric power requirements.[13] Hydro does not include non-firm power requests in the development of the annual load forecast.

3.1 Development of the Island Interconnected System Forecast

The Island Interconnected System load, exclusive of transmission losses and station service, is the summation of interconnected utility load, Industrial customer loads, and the distribution losses incurred serving the customer load requirements on the system.

The load forecast for the Island Interconnected System results from the combination of forecasts prepared for:

- Load served by Newfoundland Power;
- Industrial customers' load served by Hydro; and
- Rural load served by Hydro.

The forecast for transmission losses and station service load is then modelled using the Island Interconnected System forecast results and assumptions surrounding existing and potential generation resources.

Each of the forecasts for the Island Interconnected System is prepared using a set of inputs that form the basis for determining peak demand and energy requirements over the term of the forecast. Key inputs to the Island Interconnected System forecast include:

- Government economic forecast:
  - Hydro relies on the annual Government long-term economic forecast for economic and other provincial variable assumptions in its load forecast. This forecast provides a provincial perspective and appropriately considers local projects and demographics.

[13] Firm demand is the portion of the demand that a power supplier is obligated to provide, except when system reliability is threatened or during emergency conditions. Firm energy refers to the actual energy guaranteed to be available to meet customer requirements on an annual basis.

- Newfoundland Power load requirements:
  - Newfoundland Power provides service to the majority of customers on the Island portion of the province. In 2023, its requirements represented 86% of the Island Interconnected System demand requirements and 80% of the Island Interconnected System energy requirements.[14] Newfoundland Power's historical billing data and information contained within its five-year load forecast are used by Hydro as inputs into its long-term load forecast.
- EV adoption:
  - Considers the impact of EV adoption on demand and energy requirements. In early 2024 Hydro again engaged an external consultant, Dunsky, to develop various forecast scenarios for EV adoption in the province. A forecast scenario was chosen for the Reference Case that considers the expected trajectory of EV adoption in the region, while sensitivities consider the potential impacts of both a slower and a more accelerated adoption rate to assess impacts on load requirements in the future. All scenarios assume utility management of EV home charging will be a part of demand response programming.
- Government policies and programs:
  - Considers the impact of provincial and federal policies on demand and energy requirements. The Reference Case forecast considers the impacts of established and committed programs on system requirements (e.g., oil-to-electric home heating conversions), while sensitivity forecasts consider the implications of changes in policy or programs as well as changes in the uptake or adoption of such policies or programs.
- Electricity rates:[15,16]
  - The underlying electricity rate used in developing the 2024 Load Forecast aligns with the Government's publicly announced[17] final rate mitigation plan. The plan ensures domestic

[14] Exclusive of transmission losses and station service.
[15] The rate forecast underlying the Reference Case and load forecast scenarios can be found in Attachment 1.
[16] The rates provided herein are estimates based on assumptions made at a point in time. Actual customer rates could differ from those outlined herein for a variety of reasons, including assumptions around rate mitigation post-2030, actual customer load, rate increases associated with Newfoundland Power's costs, etc.
[17] "Provincial Government Announces Finalization of Rate Mitigation Plan," Government of Newfoundland and Labrador, May 16, 2024. https://www.gov.nl.ca/releases/2024/iet/0516n01/

residential rate increases are targeted at 2.25% annually, and provides clarity of Hydro's annual electricity rate increases associated with the Muskrat Falls Project up to and including 2030. Hydro will work with the Government 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.[18] The electricity rate also incorporates the cost of the resources identified in the Minimum Investment Required Expansion Plan from the 2024 Resource Adequacy Plan. This underlying rate forecast assumption was used in all three scenarios for the 2024 Load Forecast.

- Industrial customer load requirements:
  - Hydro works closely with its Industrial customers to forecast the demand and energy requirements associated with each customer's business activities and future potential plans. The potential for new Industrial customers is also considered in forecast development scenarios. The various projections for existing and new customers are then combined to form the basis of Hydro's load forecast of Industrial customer requirements.

3.2 Discussion of Major Inputs to the 2024 Load Forecast

Major inputs discussed here are those variables identified as inputs to the modelling and analysis that have the most potential to impact (or be impacted by) the evolving energy landscape. Some of these major inputs are also those with the most uncertainty, making it prudent to identify a range of potential outcomes.

3.2.1 Island Interconnected System Forecast Assumptions

The major inputs driving growth in the Island Interconnected System, as well as the pace of change of each, are summarized in Table 1 and are described in further detail in the following sections.

[18] For purposes of the load forecast report, Hydro assumes rate mitigation continues for the full forecast period.

Table 1: Major Inputs and Factors Driving Growth

EVs	Economic Growth	Decarbonization and Electrification	Energy Efficiency	Industrial Growth
• Total cost of EV ownership • Availability of charging infrastructure • Available vehicle supply • Government policy • Available incentives	• Population growth/immigration • Commercial development, including major projects	• Government policy, mandates and regulations • Available incentives • Carbon pricing	• Availability of new technologies • Utility programming	• Electrification of existing and new processes/facilities • Expansion

3.2.1.1 Electric Vehicles[19]

For the 2024 Load Forecast update, Hydro utilized a combination of the different forecasts provided by Dunsky to create three distinct forecasts; the EV Reference Case forecast, a Slower EV Adoption forecast, and an Accelerated EV Adoption forecast that would meet the federal government’s proposed regulated target of 100% of new light-duty vehicle sales being a zero-emission vehicle by 2035.

For the Island Interconnected System forecast scenarios, the Reference Case utilized the EV Reference forecast, the Slow Decarbonization scenario utilized the EV forecast with slower adoption, and the Accelerated Decarbonization scenario utilized the EV forecast with accelerated adoption.[20]

Chart 3 shows the impact of EV charging on the Island Interconnected System demand for the three forecast scenarios. There is a total variance of approximately 86 MW between the Slow Decarbonization and the Accelerated Decarbonization scenarios by the end of the forecast period.

[19] Information on the cumulative EV sales for the Island Interconnected System for the Reference Case and alternate scenario forecasts can be found in Attachment 1.
[20] Hydro used the “High Sensitivity” EV accelerated forecast in its Accelerated Decarbonization scenario.

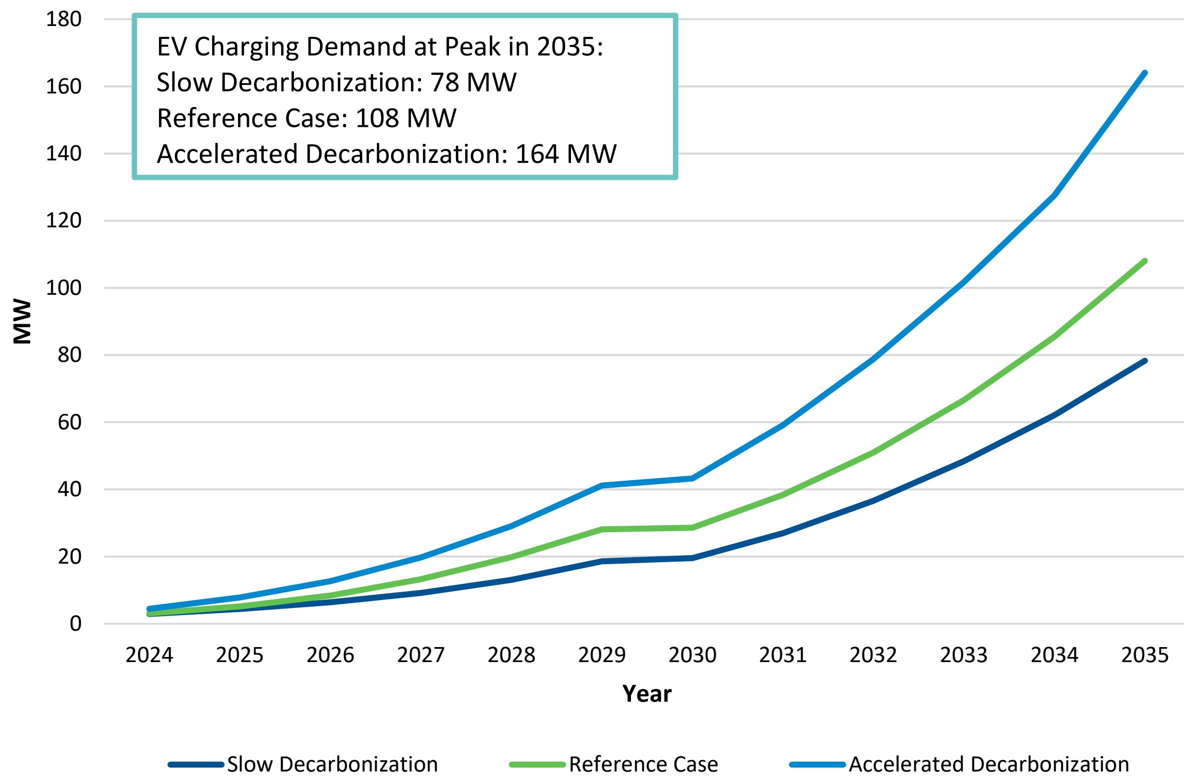

Chart 3: EV Charging Demand at Island Interconnected System Peak

1 Chart 4 shows the impact of EV charging on the Island Interconnected System on energy requirements
2 for the three forecast scenarios. There is a total variance of approximately 468 GWh between the Slow
3 Decarbonization and the Accelerated Decarbonization scenarios by the end of the forecast period.

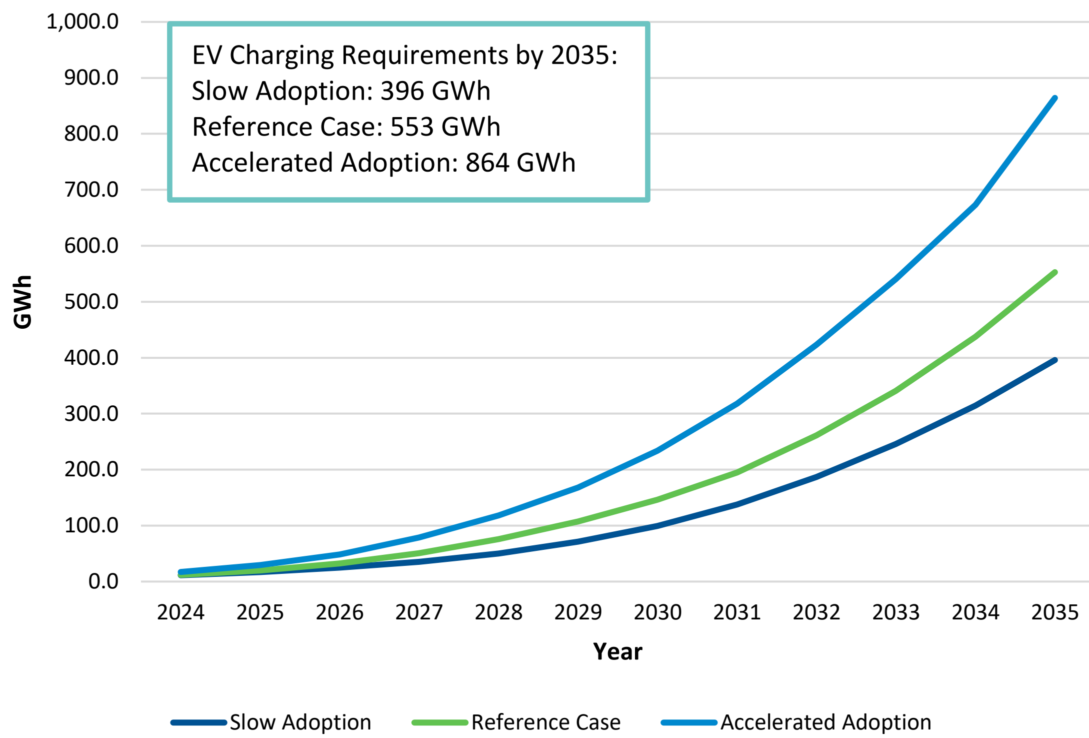

Chart 4: Island Interconnected System EV Charging Energy Requirements

It is assumed that by 2030 the system peak will include utility management of EV home charging to reduce the impact on the system peak in all scenarios. This is assumed to be achieved through EV smart chargers. Medium- and heavy-duty vehicles and buses are assumed to be managed by customers to reduce demand charges and avoid equipment upgrades. In all three forecast scenarios, it is assumed approximately 50% of home charging of light-duty vehicles will be managed during peak.[21] Managed home charging can significantly reduce evening EV load by shifting the load to the overnight period. If home charging during peak demand is not managed, it is estimated to result in an additional demand of 67 MW by 2035.

Newfoundland Power is currently completing an EV load management pilot project to assess the cost-effectiveness of different strategies to manage light-duty EV load.[22] The pilot is in its second winter and

[21] As shown in Attachment 2,"NL EV Adoption and Impacts Study – Final Results," Dunsky Energy + Climate Advisors, April 2, 2024, Slide 19.
[22] "EV Load Management Pilot Project," Newfoundland Power Inc., June 2, 2023.
http://www.pub.nl.ca/applications/NP2023ElectricVehicleLoad/app/From%20NP%20-%20%20Application%20for%20Electric%20Vehicle%20Load%20Management%20Pilot%20Project%20-%202023-06-02.PDF

Hydro is working closely with Newfoundland Power to understand the demand response potential for light-duty EVs. Results from the pilot project may be used in the development of future load forecasts to determine the potential amount of cost-effective demand management for EV home charging.

Based on Dunsky's analysis, the potential electrical system impact from EVs could be substantial by the end of the period; however, there remains a fair degree of variance in the range of forecast requirements identified between the three EV scenarios considered.[23]

3.2.1.2 Economic Information

Hydro relies on the Government's annual long-term economic forecast for economic and other provincial variables for input assumptions in the load forecast. This forecast provides a provincial perspective and appropriately considers local projects and demographics.

Economic growth is a major input into the development of the load forecast because it captures several factors that influence energy use in both the residential and general service sectors. Increased income can result in additional demand for goods and services and increased production to meet the demand generally requires more energy.

For 2024, residential regressions underlying the forecasting model rely on a prediction of customer numbers and customer average use. Hydro uses new housing starts in generating the residential customer number forecasts while household disposable income and provincial population are used to determine average customer use. The general service model for Newfoundland Power that Hydro creates continues to use adjusted gross domestic product ("GDP") and non-residential building investment as primary inputs. Forecast future sales for Hydro's rural general service sales are generated using forecasts of household disposable income and the value of fish landings.

In the underlying economic forecast for the Reference Case, there are several major projects,[24] and increased mining activity, which will positively influence provincial economic activity leading to increased investment and employment gains. The provincial population is also forecast to continue to experience growth in the near term before normalizing, following an actual increase of approximately

[23] For more information on the EV adoption and impacts provided by Dunsky, please refer to Attachment 2.
[24] These include wind-hydrogen and other major projects.

6,340, or 1.2% from July 2023 to July 2024. This population growth is similar compared to the period from July 2022 to July 2023.[25]

For the development of the Slow Decarbonization scenario, Hydro relied on an alternate scenario provided by the Government which included fewer wind-hydrogen projects, weaker long-term provincial government spending growth, and lower oil and mineral prices, resulting in a lower level of growth in residential electricity sales. Other economic indicators were held consistent with the Reference Case.

For the Accelerated Decarbonization scenario, Hydro used the Reference Case economic variables and increased the oil-to-electric conversions for Government-owned buildings, increased the mining load, and added additional industrial projects. These assumptions result in higher electricity demands compared to the Reference Case.

Table 2 shows the key economic inputs used in the forecast model for the three forecast scenarios.

Table 2: Island Interconnected System Economic Indicators

Economic Driver	Slow Decarbonization	Reference Case	Accelerated Decarbonization
Adjusted Real GDP at Basic Prices (% per year)	0.2	0.6	0.6
Real Household Disposable Income (% per year)	0.5	0.8	0.8
End of Forecast Period Population ($000)	545.8	557.3	565.8
Average Housing Starts Per Year	1,297	1,448	1,614
Cumulative Non-Residential Building Investment Over the Forecast Period ($000)	7,064	7,093	7,093

[25] The provincial population's actual increase was approximately 7,022, or 1.3% from July 2022 to July 2023. This increase was the largest annual increase in population, on an actual basis, since 1972.

1 Chart 5 and Chart 6 provide visual representations of two of the economic parameters supporting
2 growth on the Island Interconnected System in the 2024 Load Forecast; provincial population growth
3 and housing starts. The 2024 population data includes the September 2023 Statistics Canada update
4 that incorporated the 2021 Census.[26]

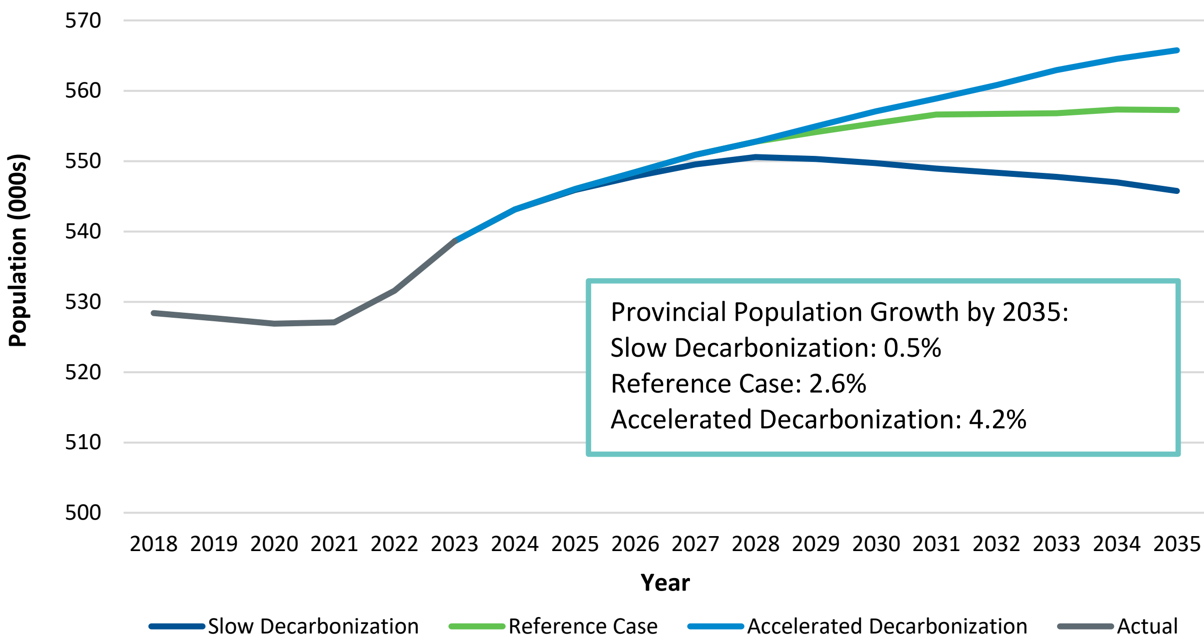

Chart 5: Actual and Forecast Provincial Population

[26] The census attempts to enumerate every person residing in Canada on the reference day, which was May 11 for 2021 Census. The revised census population numbers incorporate the Census Undercoverage Study and the Census Overcoverage Study measure, respectively, the number of people missed and the number of people enumerated more than once by the census. The population numbers were revised upwards every year from 2017 to 2022.

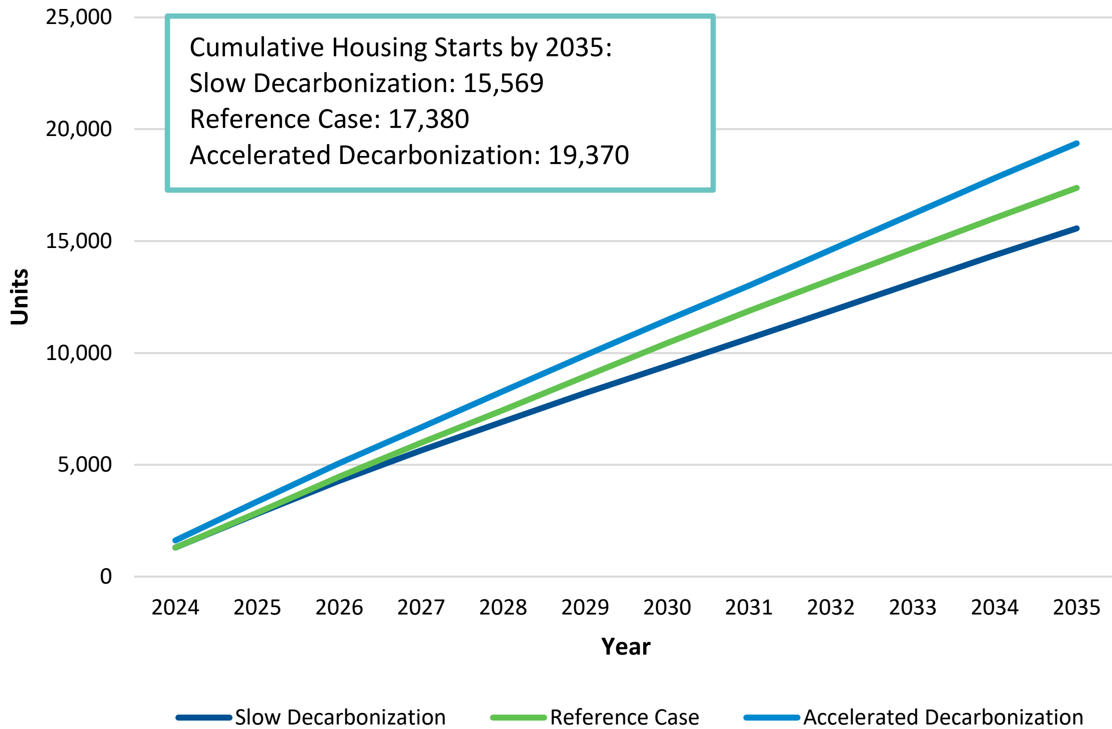

Chart 6: Cumulative Housing Starts

3.2.1.3 Decarbonization and Electrification (Utility Sales)

Government policy continues to have the greatest potential to drive decarbonization and electrification across several sectors, such as space heating and transportation, as well as influence the overall decarbonization of the province. Electrification has the potential to change the quantity and usage pattern of electricity by customers in Newfoundland and Labrador.

All levels of government are focusing on decarbonization and electrification; however, there remains uncertainty in the timing and extent to which policies may be implemented. For the 2024 Load Forecast modelling process, decarbonization factors that were considered in the development of forecast scenarios include government policy (including mandates and regulations), available incentives,[27] and the price of carbon greenhouse gas emissions.[28]

The Reference Case is representative of steady electrification in the space-heating sector. For the residential space-heating sector, it is assumed that 62% of homes that are currently oil-heated but have an oil tank that will expire during the forecast period will convert to electric heat.[29] The provincial government program for oil-to-electric conversions is delivered through the takeCHARGE program and requires participants to remove their oil tank to meet program eligibility requirements.[30] In the commercial sector, it is assumed that there will be a modest amount of Government buildings converting existing alternate fuel heating systems to electric heat, consistent with the Government's planned building conversions.[31] In forecasting the commercial sector, it is assumed that all new customers will use electric heat.

The Slow Decarbonization scenario is representative of modest electrification. It is assumed that 57% of oil-heated homes with an oil tank expiring during the forecast period will convert to electric heat. In the commercial sector, the same assumptions were used as in the Reference Case.

The Accelerated Decarbonization scenario is representative of accelerated electrification. It is assumed that 96% of oil-heated homes with an oil tank expiring during the forecast period will convert to electric heat. It is also assumed that a portion of oil-heating customers with oil tanks expiring outside of the forecast period will convert to electric heat within the next ten years. In the commercial sector, it is assumed an additional 50% of the Government's Transportation and Infrastructure buildings and Health Facilities will convert their heating systems to electric heat in addition to the Government's planned building conversions. Consistent with the Reference Case, it is assumed that all new commercial customers will use electric heat.

[27] In June 2023, the Government, in collaboration with Natural Resources Canada and Environment and Climate Change Canada, announced funding towards the implementation of new fuel switching and energy efficiency incentive programs. https://www.gov.nl.ca/releases/2023/ecc/0629n03/.
[28] In 2019, the Government of Canada set a national minimum price on carbon pollution starting at $20 per tonne, increasing by $10 in 2022 to $50 per tonne. Starting in 2023 through 2030, the minimum price increased by $15 per tonne. https://www.canada.ca/en/environment-climate-change/services/climate-change/pricing-pollution-how-it-will-work/carbon-pollution-pricing-federal-benchmark-information.html.
[29] Approximately 18,100 homes in Newfoundland and Labrador have oil tanks expiring during the forecast period.
[30] https://takechargenl.ca/oiltoelectric/.
[31] Consistent with Government's list of government building conversions dated April 2024.

Table 3 summarizes the space-heating assumptions for the Island Interconnected System included in the Reference Case and both considered alternative scenarios.

Table 3: Electrification of Space Heating

	Slow Decarbonization	Reference Case	Accelerated Decarbonization
Residential Conversions to Electric Heat During the Forecast Period (Approximate)[32]	12,700	14,000	22,000
New General Service Customers' Primary Heating Source	Electric	Electric	Electric
Government Building Conversions in 2035 (GWh)	21	21	46

Chart 7 provides a visual representation of the oil-to-electric conversions assumed through the study period.

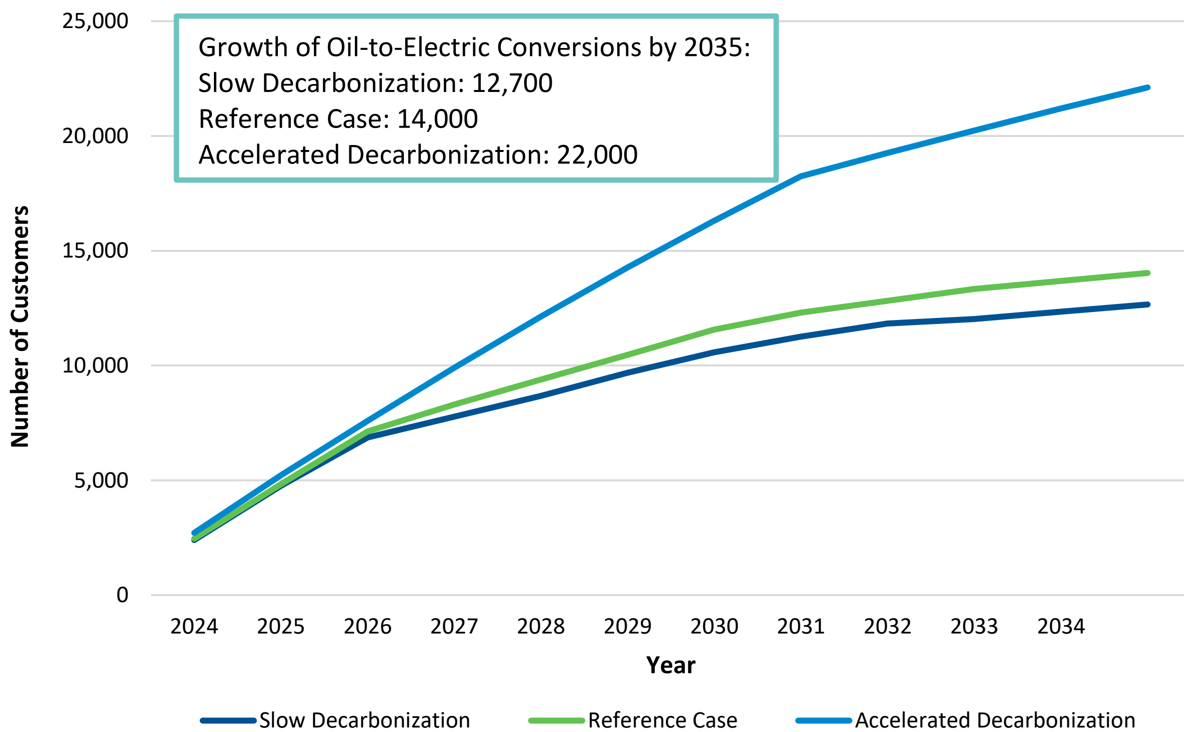

Chart 7: Cumulative Number of Residential Oil-to-Electric Conversions

[32] There are approximately 38,700 registered oil tanks on the Island.

3.2.1.4 Conservation and Energy Efficiency

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

Examples of the residential programs offered include insulation and air sealing, and heat recovery ventilators. 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 2024 Load Forecast update, an estimate of energy savings through utility conservation programs, as forecasted by takeCHARGE, was developed. This estimate was used for all three load forecast scenarios.

Over the last decade, the installation of mini-split heat pumps ("MSHP") in residential homes has grown in popularity, with Newfoundland Power's 2023 customer survey estimating that approximately 34% 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.[33] For the 2024 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 a 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 2035 approximately 71% of Newfoundland Power's residential customers who use electricity as their primary heating source will have installed MSHPs in their homes.[34]

In the Slow Decarbonization scenario, it is assumed that by the end of 2035, 76% of Newfoundland Power's residential customers with electric heat will have installed MSHPs in their homes, slightly more

[33] "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.
[34] Based on Newfoundland Power's 2023 residential customer count.

than the Reference Case and the Accelerated Decarbonization scenario due to higher energy efficiency measures.[35]

The Posterity Group is currently conducting a joint Potential Study with Newfoundland Power and Hydro on electrification, conservation and demand management measures. Completed through takeCHARGE, the Potential Study will analyze the potential for energy efficiency, demand management and electrification on the Island Interconnected System. If applicable, the study outputs may be used as input into the 2025 Load Forecast.

3.2.1.5 Industrial Customer Growth

Industrial load on the Island Interconnected System is currently comprised of six customers.[36] In recent years, Newfoundland and Labrador has seen record-setting exploration expenditures in the mining sector and there has been activity in wind hydrogen development projects. A renewable fuels refinery also commenced commercial operations in 2024.

In the Reference Case, it is assumed all current industrial customers will remain and business activities will continue at currently forecasted levels. It is also assumed there will be an additional industrial load from two customers amounting to 10 MW of firm demand each, starting in 2028 and 2032 stemming from new industrial developments.

The Slow Decarbonization scenario assumes only one additional industrial load of 10 MW stemming from new industrial developments during the same period as the Reference Case. It also assumes the same current level of load with no additional increases for existing customers.

In the Accelerated Decarbonization scenario, it is assumed all current Industrial customers will remain and business activities will continue at currently forecasted levels. This scenario also assumes that in 2028 one Industrial customer will partake in electrification initiatives, converting existing heating systems to electric heat while maintaining its existing alternate heating source as a backup. While this additional electrification load is assumed to be interruptible upon request, its impact is included in

[35] Based on Newfoundland Power's 2023 residential customer count.
[36] The sixth customer was connected to the grid in January 2024 and started drawing power from the grid late in the first quarter of 2024.

Chart 8.[37] An additional mine is added to this scenario in 2035 and 65 MW of increased industrial developments are included, beginning in 2028. As new industry development is expected to evolve, Hydro will monitor closely and adjust future scenario assumptions as required.

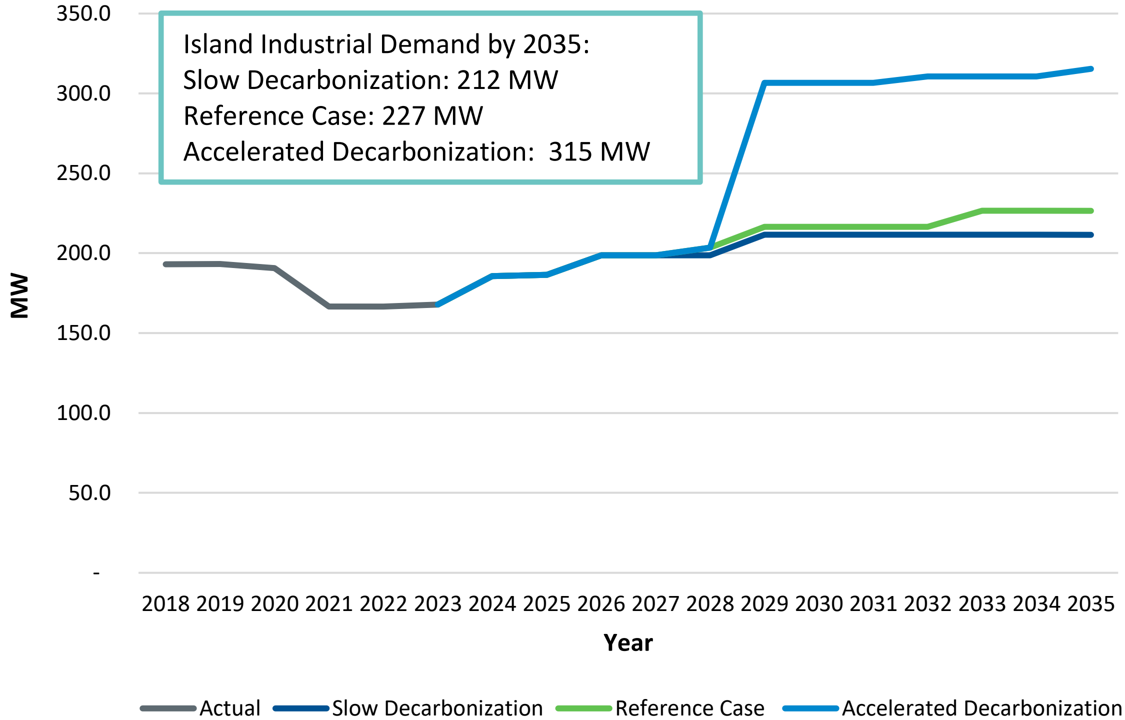

Chart 8: Island Interconnected Industrial Demand[38]

3.2.1.6 Weather Data

Weather, specifically ambient temperature, is one of the largest factors affecting customer electricity usage and demand in Newfoundland and Labrador. Hydro uses weather variables in its energy and peak models, including heating degree days[39] and wind chill. For weather variables, Hydro focuses on estimating a "normal" weather year, rather than predicting what may occur in any specific year. For the Island Interconnected System energy models, Hydro uses a rolling 30-year average for the initial starting

[37] Interruptible load is a load, typically commercial or industrial, that can be interrupted in the event of a capacity deficiency in the supplying system.
[38] Total industrial demand is the summation of firm requirements for industrial customers. Values are not reflective of industrial demand at the time of the Island Interconnected System peak.
[39] Heating degree days refers to the equal number of degrees Celsius a given day's mean temperature is below 18°C.

value of heating degree days and has implemented the use of a linear trend model to reflect gradual warming, resulting from climate change and reflecting recent winter weather history, over the forecast period. For the peak model, Hydro continues to use a rolling 30-year average wind chill value or P50 weather conditions as an input for peaking event conditions.[40]

At this time Hydro is not including additional forecast combinations for more extreme peak conditions in the development of its forecasts; however, continues to assess the impact that P90 conditions may have on the demand forecast and, on its ability, to supply customers should such conditions occur. The P90 weather condition is based on 30 years of historical wind chill values during the winter period and these assumptions increase the Island Interconnected System requirements by approximately 60 MW.[41]

4.0 Hydro's 2024 Load Forecast[42]

The 2024 reference forecast as shown in Chart 9 resulted in accelerated growth in the medium- to long-term portion of the forecast period of 2024 to 2035 as compared to that of the previous ten years. The forecast growth is driven by sustained customer growth, electrification of the transportation and space-heating sectors, and increased industrial requirements.

[40] A P50 forecast is one in which the actual peak demand is expected to be below the forecast number 50% of the time and above 50% of the time (i.e., the average forecast).
[41] A P90 forecast is one in which the actual peak demand is expected to be below the forecast number 90% of the time and above 10% of the time (i.e., there is a 10% chance of the actual peak demand exceeding the forecast peak demand).
[42] Tables detailing the 2024 Reference Case, Slow Decarbonization scenario, and Accelerated Decarbonization scenario load forecasts can be found in Attachment 1.

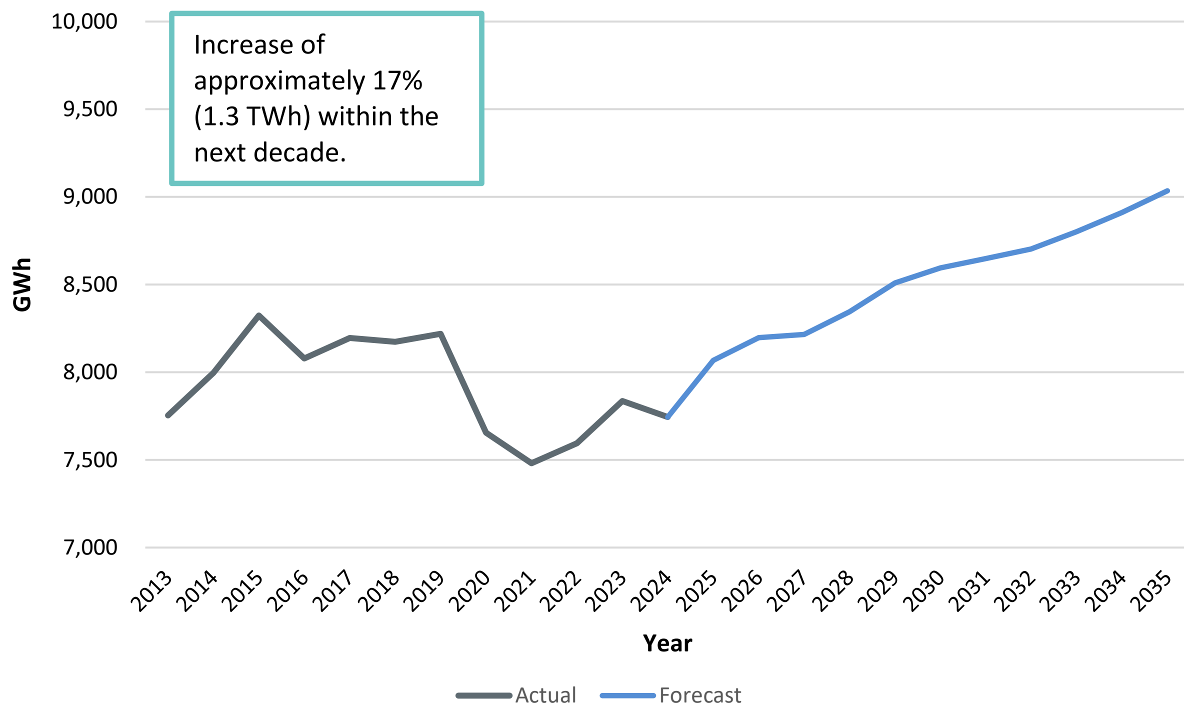

Chart 9: Island Interconnected System Net Energy Generation: Reference Case[43,44]

The following sections present the details arising from the 2024 Load Forecast for the Island Interconnected System.

4.1 Island Interconnected System Load Forecast

Hydro focused on the development of three scenarios for the Island Interconnected System. Scenarios were developed to help assess the impact of varying provincial economic growth forecasts and both the extent and timing of electrification initiatives in the heating and transportation sectors. The scenarios developed for the Island Interconnected System as part of the 2024 Load Forecast are summarized in Figure 2. The analysis completed for the 2025 Build Application filing used the 2024 Reference Case and the Slow Decarbonization load forecast as presented in this report.

[43] Newfoundland and Labrador Interconnected System net generation is total generation requirements less transmission losses and stations service.
[44] Historical values are not weather normalized.

Slow Decarbonization

- Results in lower load growth relative to the Reference Case; reflects slower decarbonization combined with a steady, slower electrification of the transportation sector, slower population growth, and lower housing starts.

Reference Case

- The expected load growth case; reflective of expected population growth and current/committed Government decarbonization policies and programs.

Accelerated Decarbonization

- Results in higher load growth relative to the Reference Case; reflects accelerated policy-driven decarbonization, combined with accelerated transportation electrification, higher housing starts and an increase in industrial load requirements.

Figure 2: Island Interconnected System 2024 Load Forecast Scenarios

The Reference Case is reflective of a future that can be primarily defined by steady decarbonization and economic growth and favourable economics driven primarily by a strong population forecast. In the residential space heating sector, it is assumed there will be steady conversions from oil heating systems to electric heating systems. This is driven primarily by the implementation of new fuel switching and energy efficiency incentive programs as part of a collaboration between the Government, Natural Resources Canada, and Environment and Climate Change Canada. In the transportation sector, Dunsky continues to estimate that EV adoption in Newfoundland and Labrador will not meet the federal government target that 100% of sales of light-duty vehicles must be zero emission. However, there is still a strong uptake of EVs forecast to occur, with approximately 93,660 zero-emission light-duty vehicles on the road in the province in 2035.[45]

The first alternative scenario, Slow Decarbonization, contemplates a future with slower decarbonization efforts, as compared to the Reference Case. In the residential space-heating sector, it is assumed there will be a modest conversion from oil to electric heating as compared to the Reference Case. A steady uptake of EVs is forecast, with approximately 68,560 zero-emissions light-duty vehicles on the road in

[45] There are approximately 414,000 vehicles on the road in Newfoundland and Labrador in 2022 as shown in Attachment 2 “NL EV Adoption and Impacts Study – Final Results,” Dunsky Energy + Climate Advisors, April 2, 2024, Slide 11.

the province in 2035. This scenario also assumes slightly weaker economics driven by a reduced population growth forecast.

The second alternative scenario, Accelerated Decarbonization, contemplates a future with accelerated decarbonization efforts, as compared to the Reference Case. In the residential space heating sector, it is assumed there will be accelerated conversions from oil to electric heating. In the transportation sector, an accelerated uptake of zero-emissions light-duty vehicles is assumed, including achieving the Government of Canada's intention to set a mandatory target for sales of all new light-duty cars and passenger trucks to be zero-emission by 2035,[46] with approximately 150,728 zero-emission light-duty vehicles on the road in Newfoundland in 2035.[47] This scenario also includes additional industrial load, stemming from new industrial demand in the province including increased mining activity and the electrification of existing industrial load.

Table 4 summarizes the major drivers for each of the alternative future forecasts that were described in detail in Section 3.2.

[46] Government of Canada. (2021). *Building a green economy: Government of Canada to require 100% of car and passenger truck sales be zero-emission by 2035 in Canada.* Transport Canada. 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.
[47] The EV assumption is the high growth case with high sensitivity.

Table 4: Major Input Comparison of the Alternative Future Forecasts

Scenario	Slow Decarbonization	Reference Case	Accelerated Decarbonization
Scenario Description	Slower decarbonization and transportation electrification	Steady decarbonization and transportation electrification driven by Government policy and programs	Accelerated decarbonization and transportation electrification
Residential Rates	Reference	Reference	Reference
Electric Vehicles	Slower adoption	Reference	Accelerated adoption
Economic Growth	Lower economic forecast	Reference	Reference
Decarbonization Policy (Government Programming)	Slower change	Reference	Accelerated change
Energy Efficiency	Accelerated change	Reference	Reference
Industrial Growth	Lower growth	Reference	High growth

Chart 10 and Chart 11 provide a visual representation of the 2024 Load Forecast scenarios for demand and energy developed for the Island Interconnected System compared against historical system demand.

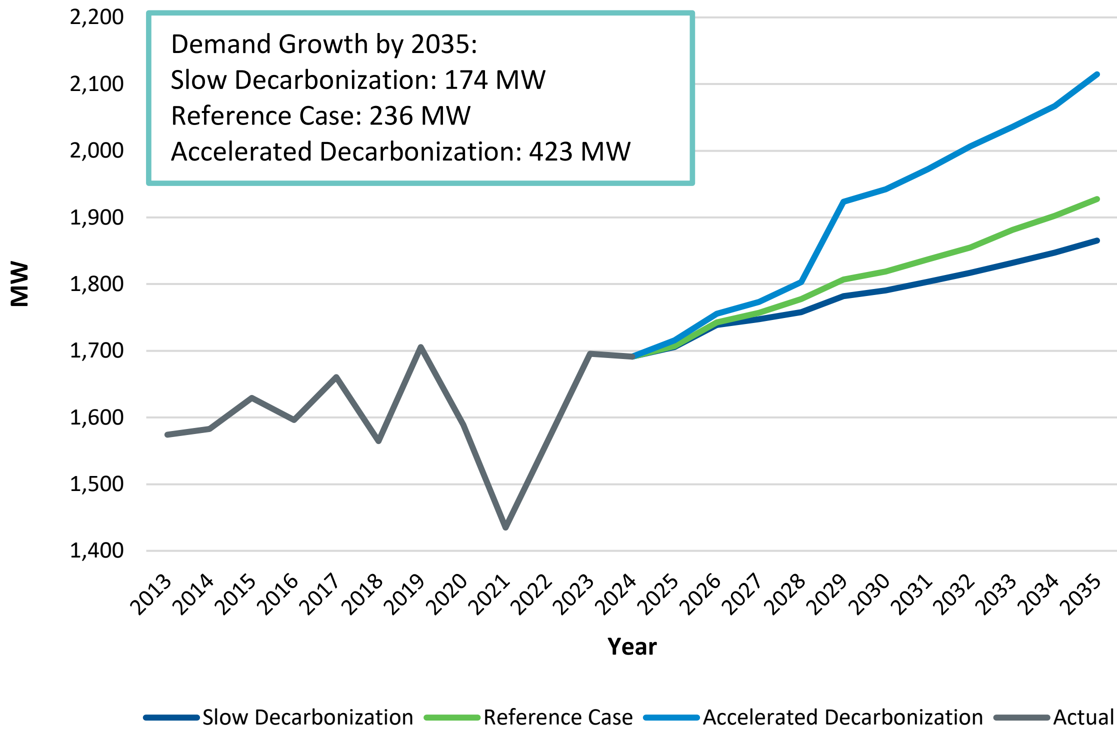

Chart 10: Island Interconnected System Customer Coincident Demand Requirements[48,49,50]

48 Island Interconnected System demand requirements are exclusive of station service and transmission losses.
49 Historical values are not weather normalized. Forecast values are based on normalized weather conditions.
50 The significant decline in demand in 2020 and 2021 was due to the effects of the COVID-19 pandemic.

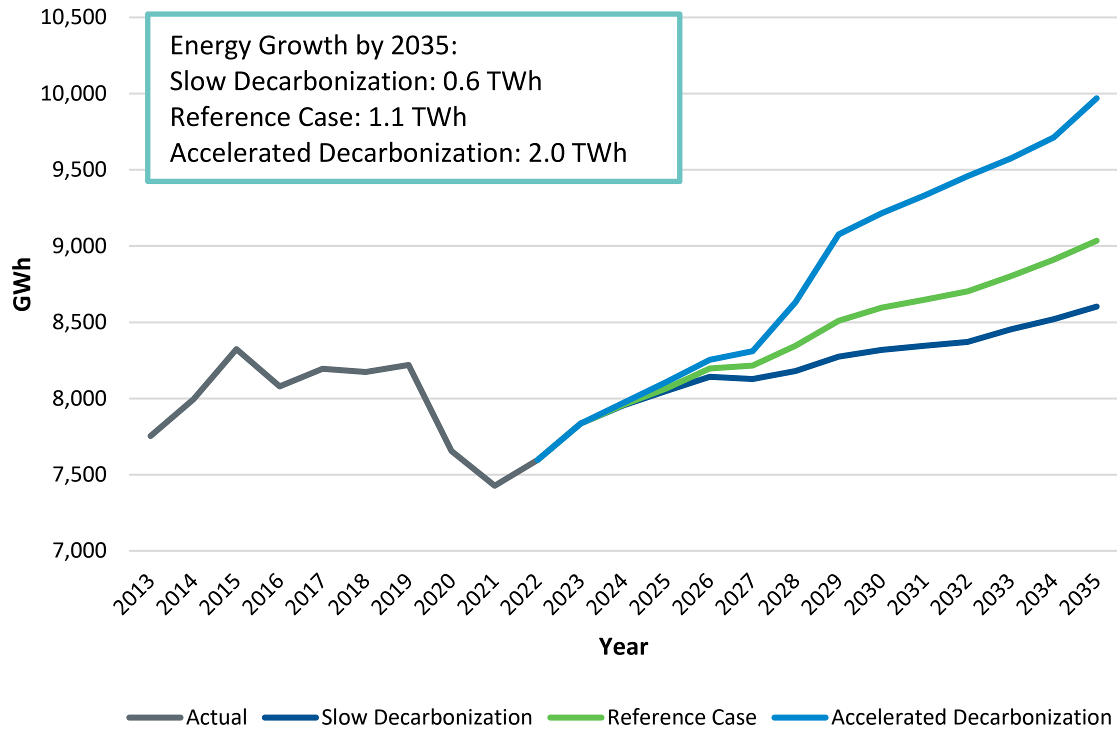

Chart 11: Island Interconnected System Energy Requirements[51,52,53]

Of note is the potential range of load possibilities between the three scenarios. As shown in Table 5, there is a total variance in 2035 of approximately 249 MW of peak demand between the Slow Decarbonization and the Accelerated Decarbonization scenarios, with approximately 86 MW of that variance resulting from the difference in EV forecasts at peak. There is a margin of 1,370 GWh in energy requirements in 2035 between the lower and upper bounds provided by the Slow Decarbonization and the Accelerated Decarbonization scenarios, with 460 GWh representing the variance between the EV forecasts. The disparity between forecasts at the end of the forecast period reflects both the inherent uncertainty in the later period of the forecast (an intrinsic component of load forecasting) and the uncertainty around the potential timing and extent of electrification between 2024 and 2035. Table 5 summarizes the demand and energy requirements for customers and EVs between the Reference Case and the two alternative scenarios.

[51] Island Interconnected System energy requirements are exclusive of station service and transmission losses.
[52] Historical values are not weather-normalized.
[53] The significant decline in energy requirements in 2020 and 2021 was due to the effects of the COVID-19 pandemic.

Table 5: Island Interconnected System Requirements in 2035[54]

	Customer Coincident Demand (MW)	Customer Energy Requirements (GWh)	EV Demand Component (MW)	EV Energy Consumption (GWh)
Slow Decarbonization	1,865	8,600	78	400
Reference Case	1,928	9,040	108	550
Accelerated Decarbonization	2,115	9,970	164	860

The Slow Decarbonization scenario represents an approximate 4.9% decrease in total energy consumption compared to the Reference Case and a 3.2% decrease in customer demand. The Accelerated Decarbonization scenario represents an approximate 9.7% increase in demand and a 10.3% increase in energy consumption compared to the Reference Case.

Figure 3 provides a breakout of the Island Interconnected System requirements, which are subsequently discussed in detail in Sections 4.1.1 through 4.1.3.

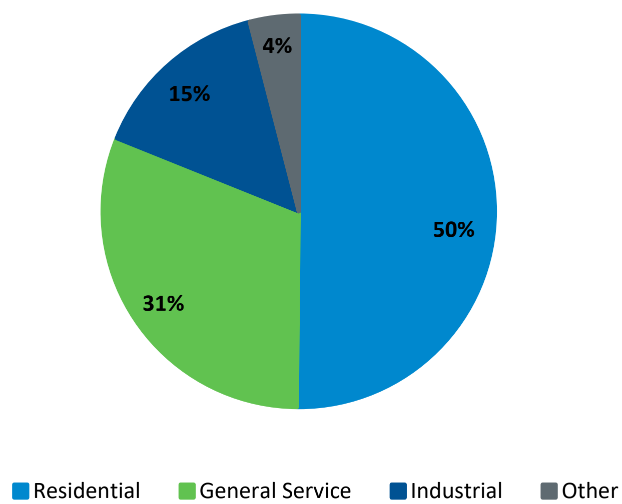

Figure 3: Breakout of Island Interconnected System Requirements[55]

[54] Excludes transmission losses and station service.
[55] Exclusive of transmission losses and station service.

4.1.1 Residential Sales

In 2023, Residential sales made up 50% of the total Island Interconnected System bulk energy deliveries (47% directly by Newfoundland Power and 3% by Hydro).[56] Growth in the residential sector is driven by new customer additions, which is driven by population growth.

Residential space heating in Newfoundland is largely electrified with over 71% of customers already using electricity as their primary heating source.[57] Over the last ten years, while there has been an increase in the number of customers, average customer use has been decreasing, driven by the installation of MSHP in homes already heating with electric heat. More recently, provincial and federal government funding programs have targeted homes that do not have electricity as the primary heating source to supplement or replace their existing heating source with electric heat. As space heating continues to electrify, growth in electricity use on the Island, driven by switching from oil or wood to electric heat, will be partially offset by greater penetration of energy-efficient heat pumps in electrically heated homes. A large number of conversions to electric space heating will result in increased peak demand in the winter period, and the strong uptake of MSHP may result in increased demand in the summer period to meet cooling needs.

Chart 12 depicts the forecast of Residential sales under the three Island Interconnected System scenarios both including and excluding EV sales to help visualize the impact EVs are forecasted to have on sales. The variance shown between the Slow Decarbonization and the Accelerated Decarbonization scenarios is approximately 559 GWh in 2035, with 301 GWh representing the difference in EV forecasts. The remaining variance primarily reflects the difference in economic growth and penetration levels of electric heat in the forecasts.

[56] Bulk energy deliveries do not include transmission losses or station service.
[57] Based on Newfoundland Power and Hydro 2023 billing data.

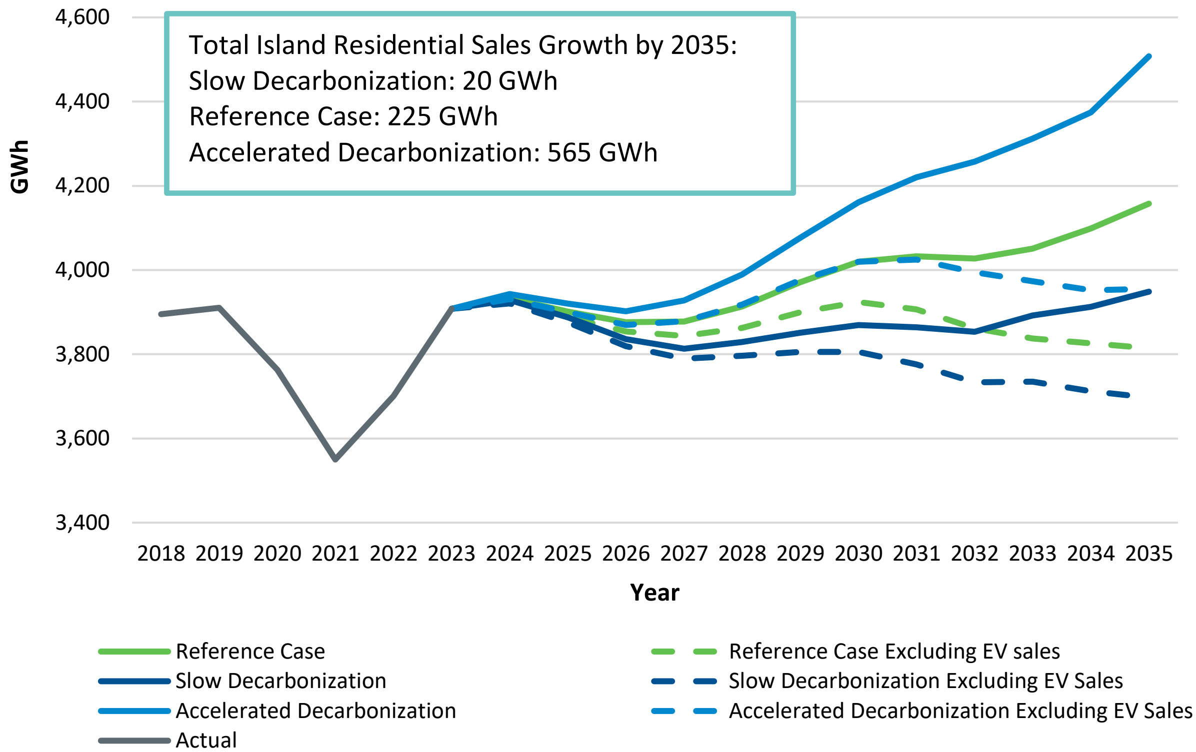

Chart 12: Island Interconnected Residential Sales[58,59]

In the Slow Decarbonization scenario, residential sales are expected to increase by approximately 1%, including EVs; however, the change in residential sales would decline without EV sales over the load forecast period. In the Reference Case, residential sales are expected to grow by approximately 6% including EVs, and decline excluding EV sales. In the Accelerated Decarbonization scenario, residential sales are expected to increase by approximately 14% with EVs; the change is negligible without EVs.

4.1.2 General Service Sales

The General Service classification includes commercial (e.g., retail, hospitality, offices, etc.) and institutional customers (e.g., hospitals, schools, universities, etc.). In 2023, General Service sales accounted for 31% of total Island Interconnected System bulk energy deliveries (29% Newfoundland Power, 2% Hydro).[60]

[58] Historical values are not weather-normalized.
[59] The significant decline in energy requirements in 2020 and 2021 was due to the effects of the COVID-19 pandemic.
[60] Bulk energy deliveries do not include transmission losses and station service.

Over the last decade, General Service sales have remained relatively stable; however, General Service sales are expected to grow by approximately 19% from 2024 to 2035 in the Reference Case. The growth in the General Service sector is primarily driven by the electrification of space heating in buildings and the electrification of the transportation sector.

Chart 13 depicts the forecast of General Service sales under the three Island Interconnected System scenarios. The underlying economic forecasts affecting General Service sales are the same in both the Reference Case and the Accelerated scenario, and a more conservative outlook in the Slow Decarbonization scenario. The higher load growth in the Accelerated Decarbonization scenario is due to increased EVs and electrification.

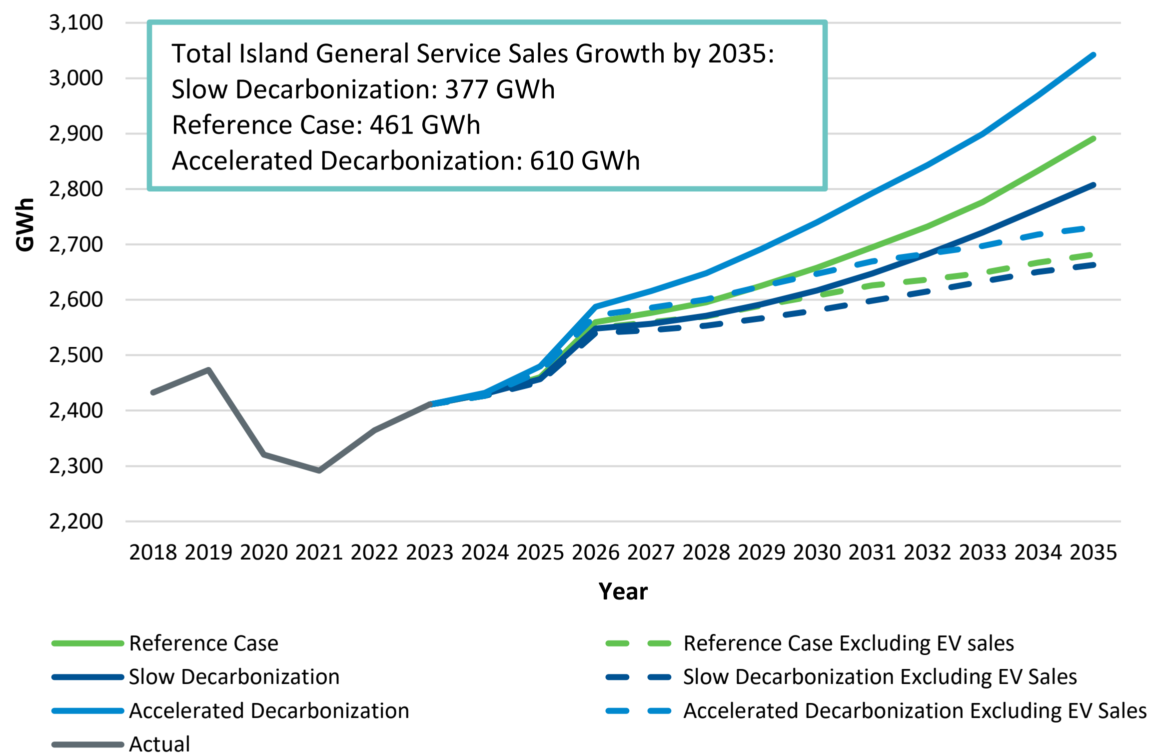

Chart 13: Island Interconnected General Service Sales[61,62]

[61] Historical values are not weather normalized.
[62] The significant decline in energy requirements in 2020 and 2021 was due to the effects of the COVID-19 pandemic.

The variance between the Slow Decarbonization and the Accelerated Decarbonization scenarios, including EV sales is approximately 235 GWh by 2035. A sharp increase in General Service sales is observed between 2024 and 2026 as the result of the electrification of oil boilers at Memorial University of Newfoundland.

4.1.3 Industrial Sales

In 2023, sales to Industrial customers accounted for 15% of Island Interconnected System bulk energy deliveries. While the makeup of Industrial customers has been consistent, the idling of the oil refinery at Come by Chance in 2020 resulted in reduced requirements in recent years. In 2021, Cresta Fund Management[63] acquired a controlling stake in the refinery, with plans to convert operations to renewable fuel production. Commercial production was announced in February 2024[64] and the 2024 forecast reflects current electricity demand.

The Valentine Gold mining project connected to the Island Interconnected System in January 2024; however, it did not draw power from the grid until late in the first quarter of 2024. Electricity requirements for the mine are expected to ramp up in 2025, with the first production from the mine expected in the second quarter of 2025.

Chart 14 shows the industrial requirements for the three forecast scenarios for the Island Interconnected System. While additional industrial growth is assumed in all three scenarios, the Accelerated Decarbonization scenario assumes there will be higher requirements from additional new projects and that some electrification of current loads will occur; however, the impact of the electrification is not material.

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[63] Braya Renewable Fuels (Newfoundland) GP Inc. ("Braya") operates the renewable fuels refinery in Come By Chance. Braya's ownership group includes Cresta Fund Management, North Atlantic Refining Corporation, which is managed by Silverpeak, and Energy Capital Partners.
[64] https://brayafuels.com/wp-content/uploads/2024/02/Braya-Renewable-Fuels-Commercial-Operations-Release-FINAL-2-22-2024.pdf.

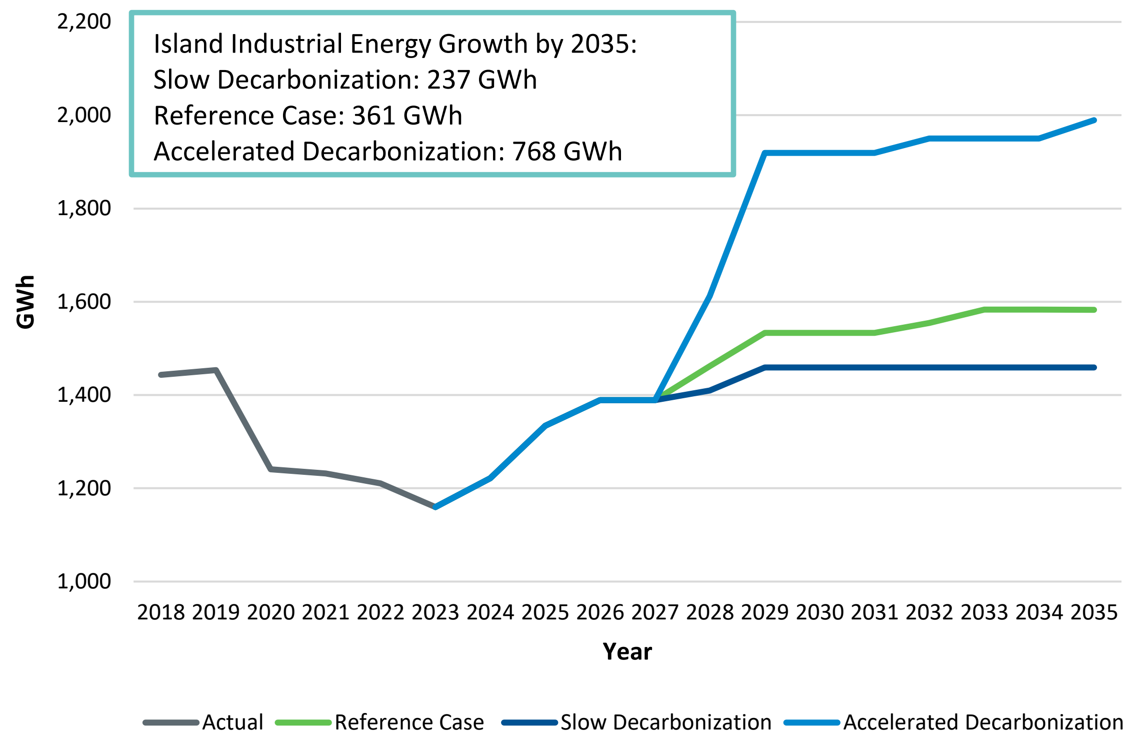

Chart 14: Island Industrial Customers Total Energy Requirements[65]

1 # 5.0 2023 versus 2024 Load Forecasts

2 ## 5.1 Customer Demand Comparison

3 As shown in Chart 15 and Chart 16, the Slow Decarbonization and Reference Cases in 2024 are similar to
4 those in 2023.

5 The 2024 Load Forecast is slightly more conservative in the both the Slow Decarbonization and
6 Reference Cases when compared to 2023. The 2024 Reference Case load forecast demand reduced by
7 1.2%, or 22 MW, by 2034 compared to the demand requirement identified in the 2023 Reference Case
8 load forecast. In addition, the 2024 Slow Decarbonization load forecast demand reduced by 0.4%, or
9 8 MW, by 2034 as compared to the demand requirement calculated for the 2023 Slow Decarbonization
10 load forecast. The slight decline is reflective of updated economic activity and inputs such as housing
11 starts.

[65] Historical values are not weather-normalized.

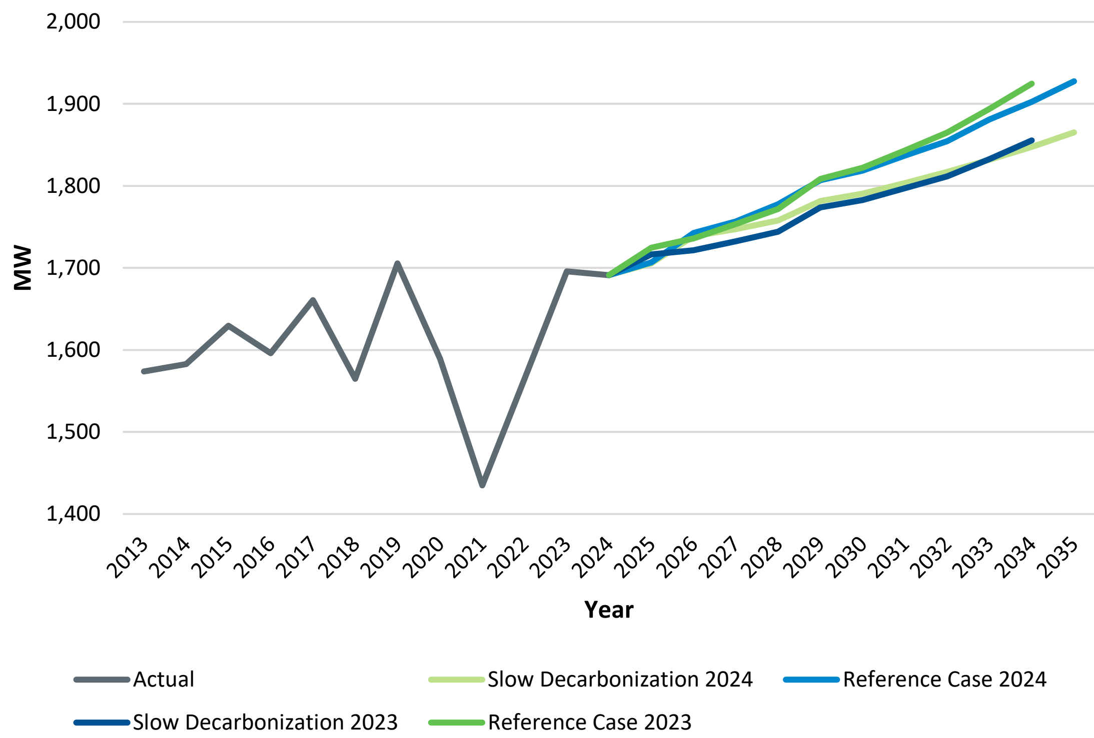

Chart 15: **Island Interconnected System Annual Customer Coincident Demand Requirements Comparisons**[66,67,68]

5.2 Energy Requirements Comparison

As shown in Chart 16, the Slow Decarbonization and Reference Cases in 2024 are similar to those in 2023.

Similar to the demand forecast, the 2024 energy forecast is slightly more conservative in both the Slow Decarbonization and Reference cases when compared to 2023. The 2024 Reference Case load forecast energy reduced by 2.8%, or 238 GWh by 2034 compared to the energy requirement identified in the 2023 Reference Case load forecast. In addition, the 2024 Slow Decarbonization load forecast energy reduced by 2.1%, or 169 GWh by 2034 as compared to the energy requirement calculated for the 2023

[66] The Island Interconnected System annual customer coincident demand is reflective of the total Island Interconnected System demand less transmission losses and station service load.
[67] Historical values are not weather-normalized.
[68] The significant decline in demand in 2020 and 2021 was due to the effects of the COVID-19 pandemic.

Slow Decarbonization load forecast. The slight decline is reflective of updated technology changes such as MSHPs and an increase in electricity rates compared to the 2023 load forecast.

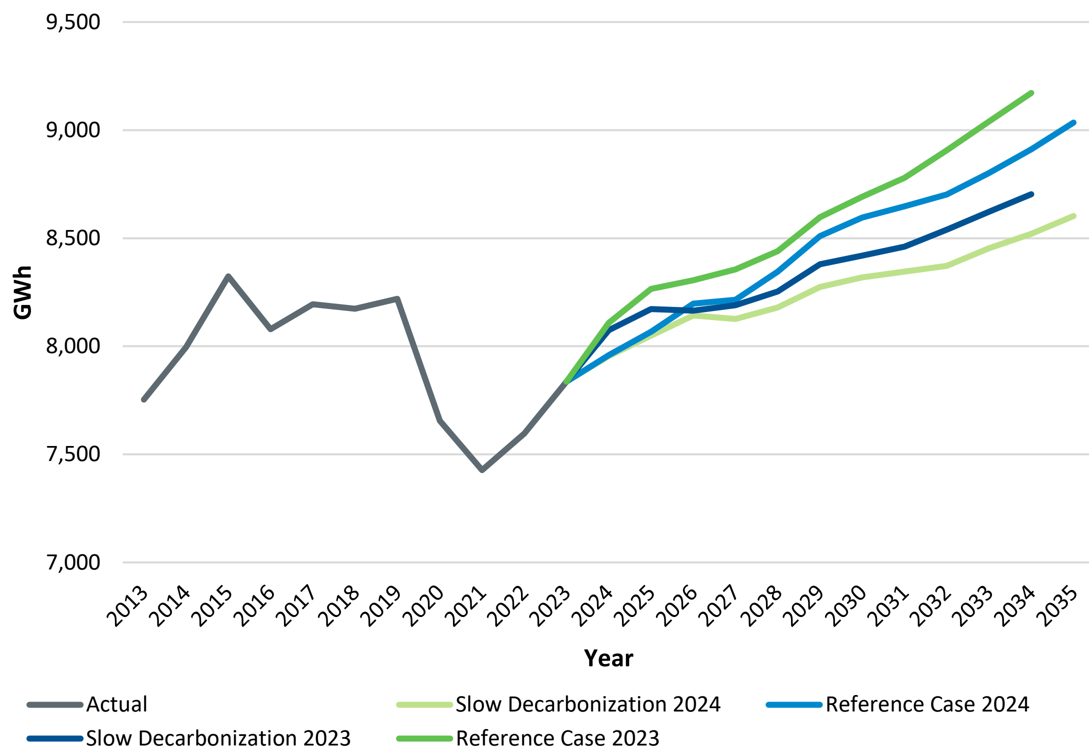

Chart 16: **Island Interconnected System Annual Energy Requirements Comparisons**[69,70]

6.0 Conclusion

The load forecasts presented in this report form the basis for the analysis completed for Hydro's 2025 Build Application, as they best reflect the range of potential outlooks for system planning at the time of filing. Planning is a dynamic process and requires the analysis of a variety of scenarios that reflect the range of possibilities for key drivers to better understand both the resource adequacy risks as well as the potential methods to help mitigate the risks. Hydro adheres to this aspect of resource planning practice by considering several scenarios that address expected and potential expectations for economic growth and Government decarbonization policies and programs. As noted during Daymark's independent

[69] Historical values are not weather-normalized.
[70] The significant decline in energy in 2020 and 2021 was due to the effects of the COVID-19 pandemic.

review conducted in 2023, Hydro's load forecast methodology reflects standard industry approaches for assessing potential growth.[71] As noted previously, the parties to the 2024 Resource Adequacy Plan agreed that the load forecast methodology used by Hydro in the 2023 Load Forecast is consistent with utility industry standards; the 2024 Load Forecast utilizes the same methodology.

Government policy and programming in Canada and Newfoundland and Labrador are continuing to influence a transformation of the Newfoundland and Labrador electric power systems. The forecasts presented highlight the broad range of future alternatives, primarily based on the variation and uncertainty around decarbonization, which impacts the timing and extent of electrification activities. Combined with the recent population growth in the province, this could continue to drive higher economic growth.

At a minimum, the Slow Decarbonization scenario is forecasting additional demand of 174 MW and 0.6 TWh of energy required by 2035. Comparing against the 2023 Slow Decarbonization scenario, the demand reduced by 0.4%, or 8 MW by 2034, which is a negligible difference. As the Island Interconnected System is currently capacity-constrained, reliability concerns remain. Given the timeframe to construct new assets, it is imperative to approve new resource options in a timely manner to maintain a reliable electricity system. Hydro is confident that its 2024 Load Forecast provides comprehensive input into the analysis supporting the 2025 Build Application to ensure appropriate planning for the future of the provincial electricity grid.

Hydro remains committed to annually updating the load forecast and creating additional scenarios to reflect changes in the planning environment to support future resource planning analysis, including the submission of the 2025 Build Application. As is the case with all forecasting analyses, improvements in the underlying methodologies are expected and planned to occur in each successive forecast update to reflect new information and industry changes. Annual updates will also address the emergence of additional information on customer adoption of policy-driven programs, responses to pricing, and the general economic climate.

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[71] "R&RA 2024: Independent Load Forecasting Process Review," Daymark Energy Advisors, March 22, 2024, sec. II(C), p. 15.

Attachment 1

Supporting Tables

newfoundland labrador hydro

Table 1: 2024 Planning Load Forecast – Reference Case
Primary Forecast Inputs and Island Interconnected System Utility Impacts

Economic Forecast	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Gross Domestic Product (2012$, MM)[1]	22,750	22,807	23,510	23,663	23,896	24,374	24,871	25,243	24,948	24,639	24,881	24,574
Growth Rate . . . (%)	-0.3	0.3	3.1	0.7	1.0	2.0	2.0	1.5	-1.2	-1.2	1.0	-1.2
Household Disposable Income (2012$, MM)	13,104	13,227	13,510	13,711	13,806	14,122	14,290	14,339	14,234	14,266	14,303	14,138
Growth Rate . . . (%)	2.3	0.9	2.1	1.5	0.7	2.3	1.2	0.3	-0.7	0.2	0.3	-1.2
Commercial Bldg. Investment (2012$, MM)	625	615	581	584	590	589	588	587	585	584	584	582
Growth Rate . . . (%)	-2.9	-1.6	-5.6	0.5	1.0	0.0	-0.2	-0.2	-0.2	-0.2	-0.1	-0.3
Housing Starts	1,300	1,554	1,615	1,526	1,447	1,508	1,481	1,457	1,387	1,381	1,378	1,346
Population (000's)	543	546	548	551	553	554	555	557	557	557	557	557

Island Interconnected Utility Impacts[2]	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Domestic Customers (000's)	261	263	264	266	268	269	271	272	274	275	276	278
Domestic Sales (GWh)	3,933	3,901	3,876	3,878	3,914	3,971	4,020	4,033	4,027	4,051	4,099	4,158
Growth Rate . . . (%)	0.6	-0.8	-0.6	0.0	0.9	1.5	1.2	0.3	-0.1	0.6	1.2	1.4
Electric Heat Market Share (%)	73	74	75	76	76	77	77	78	78	79	79	79
General Service Customer Sales (GWh)	2,430	2,460	2,560	2,576	2,595	2,625	2,658	2,695	2,732	2,776	2,833	2,891
Growth Rate . . . (%)	0.8	1.2	4.0	0.6	0.7	1.2	1.2	1.4	1.4	1.6	2.0	2.1
Street & Area Lighting Sales (GWh)	25	23	20	19	19	19	19	19	19	19	19	19
Distribution Losses (GWh)[3]	349	349	352	353	356	361	365	367	369	373	378	384
Total Utility Requirements (GWh)	6,738	6,733	6,809	6,826	6,884	6,976	7,062	7,114	7,148	7,219	7,328	7,452
Growth Rate . . . (%)	0.9	-0.1	1.1	0.3	0.8	1.3	1.2	0.7	0.5	1.0	1.5	1.7

Table 2: 2024 Planning Load Forecast – Slow Decarbonization Scenario
Primary Forecast Inputs and Island Interconnected System Utility Impacts

Economic Forecast	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Gross Domestic Product (2012$, MM)[4]	22,750	22,632	22,784	22,550	22,605	22,633	22,858	23,090	23,378	23,547	23,681	23,218
Growth Rate . . . (%)	-0.3	-0.5	0.7	-1.0	0.2	0.1	1.0	1.0	1.2	0.7	0.6	-2.0
Household Disposable Income (2012$, MM)	13,104	13,147	13,213	13,303	13,361	13,455	13,516	13,568	13,607	13,640	13,655	13,540
Growth Rate . . . (%)	2.3	0.3	0.5	0.7	0.4	0.7	0.5	0.4	0.3	0.2	0.1	-0.8
Commercial Bldg. Investment (2012$, MM)	625	615	579	582	588	587	585	584	582	581	579	578
Growth Rate . . . (%)	-2.9	-1.7	-5.8	0.6	1.0	-0.2	-0.3	-0.3	-0.3	-0.2	-0.2	-0.2
Housing Starts	1,300	1,515	1,478	1,357	1,282	1,267	1,221	1,229	1,234	1,240	1,245	1,201
Population (000's)	543	546	548	550	551	550	550	549	548	548	547	546

Island Interconnected Utility Impacts[5]	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Domestic Customers (000's)	261	263	264	266	267	268	270	271	272	273	275	276
Domestic Sales (GWh)	3,929	3,887	3,836	3,813	3,829	3,851	3,870	3,864	3,854	3,892	3,913	3,949
Growth Rate . . . (%)	0.5	-1.1	-1.3	-0.6	0.4	0.6	0.5	-0.2	-0.3	1.0	0.5	0.9
Electric Heat Market Share (%)	73	74	75	75	76	77	77	77	78	78	78	78
General Service Customer Sales (GWh)	2,430	2,457	2,548	2,557	2,571	2,592	2,617	2,648	2,682	2,721	2,764	2,807
Growth Rate . . . (%)	0.8	1.1	3.7	0.4	0.6	0.8	1.0	1.2	1.3	1.4	1.6	1.6
Street & Area Lighting Sales (GWh)	25	23	20	19	19	19	19	19	19	19	19	19
Distribution Losses (GWh)[6]	349	348	350	349	350	353	355	356	357	361	365	368
Total Utility Requirements (GWh)	6,733	6,715	6,754	6,738	6,770	6,815	6,860	6,886	6,912	6,994	7,061	7,144
Growth Rate . . . (%)	0.8	-0.3	0.6	-0.2	0.5	0.7	0.7	0.4	0.4	1.2	1.0	1.2

[1] Adjusted GDP excludes production related income earned by the non-resident owners of mining, oil, and gas projects.
[2] Includes Newfoundland Power and Hydro Rural.
[3] Includes company use.
[4] Adjusted GDP excludes production related income earned by the non-resident owners of mining, oil, and gas projects.
[5] Includes Newfoundland Power and Hydro Rural.
[6] Includes company use.

Table 3: 2024 Planning Load Forecast – Accelerated Decarbonization Scenario Primary Forecast Inputs and Island Interconnected System Utility Impacts

Economic Forecast	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Gross Domestic Product (2012$, MM)[7]	22,750	22,807	23,510	23,663	23,896	24,374	24,871	25,243	24,948	24,639	24,881	24,574
Growth Rate . . . (%)	-0.3	0.3	3.1	0.7	1.0	2.0	2.0	1.5	-1.2	-1.2	1.0	-1.2
Household Disposable Income (2012$, MM)	13,104	13,227	13,510	13,711	13,806	14,122	14,290	14,339	14,234	14,266	14,303	14,138
Growth Rate . . . (%)	2.3	0.9	2.1	1.5	0.7	2.3	1.2	0.3	-0.7	0.2	0.3	-1.2
Commercial Bldg. Investment (2012$, MM)	625	615	581	584	590	589	588	587	585	584	584	582
Growth Rate . . . (%)	-2.9	-1.6	-5.6	0.5	1.0	0.0	-0.2	-0.2	-0.2	-0.2	-0.1	-0.3
Housing Starts	1,619	1,743	1,709	1,606	1,614	1,602	1,581	1,542	1,593	1,611	1,602	1,548
Population (000's)	543	546	548	551	553	555	557	559	561	563	565	566

Island Interconnected Utility Impacts[8]	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Domestic Customers (000's)	262	263	265	267	268	270	272	273	275	277	278	280
Domestic Sales (GWh)	3,943	3,920	3,902	3,928	3,989	4,077	4,161	4,220	4,258	4,312	4,374	4,508
Growth Rate . . . (%)	0.9	-0.6	-0.5	0.7	1.6	2.2	2.1	1.4	0.9	1.3	1.4	3.0
Electric Heat Market Share (%)	73	74	75	76	78	79	80	81	81	82	82	82
General Service Customer Sales (GWh)	2,432	2,480	2,587	2,616	2,648	2,692	2,740	2,793	2,844	2,899	2,969	3,042
Growth Rate . . . (%)	0.8	2.0	4.3	1.1	1.2	1.7	1.8	1.9	1.8	2.0	2.4	2.5
Street & Area Lighting Sales (GWh)	25	23	20	19	19	19	19	19	19	19	19	19
Distribution Losses (GWh)[9]	350	351	356	359	364	370	377	383	388	393	400	411
Total Utility Requirements (GWh)	6,750	6,774	6,865	6,921	7,020	7,158	7,297	7,415	7,508	7,624	7,762	7,980
Growth Rate . . . (%)	1.1	0.4	1.3	0.8	1.4	2.0	1.9	1.6	1.3	1.5	1.8	2.8

Table 4: 2024 Planning Load Forecasts Island Interconnected System Load Summary[10]

Slow Decarbonization Case	2024[11]	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Total Island Requirements (GWh)	7,955	8,049	8,142	8,127	8,231	8,348	8,394	8,420	8,467	8,577	8,644	8,727
Growth Rate . . . (%)		1.2	1.2	-0.2	1.3	1.4	0.5	0.3	0.6	1.3	0.8	1.0
Island Customer Coincident Peak Demand (MW)	1,691	1,706	1,739	1,747	1,762	1,786	1,795	1,808	1,821	1,845	1,861	1,879
Growth Rate . . . (%)		0.9	1.9	0.5	0.9	1.4	0.5	0.7	0.7	1.3	0.8	1.0

Reference Case	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Total Island Requirements (GWh)	7,959	8,067	8,197	8,215	8,346	8,510	8,595	8,648	8,702	8,802	8,912	9,035
Growth Rate . . . (%)		1.4	1.6	0.2	1.6	2.0	1.0	0.6	0.6	1.1	1.2	1.4
Island Customer Coincident Peak Demand (MW)	1,691	1,707	1,742	1,757	1,778	1,807	1,819	1,837	1,855	1,881	1,902	1,928
Growth Rate . . . (%)		0.9	2.1	0.8	1.2	1.6	0.6	1.0	1.0	1.4	1.1	1.3

Accelerated Decarbonization Case	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Total Island Requirements (GWh)	7,971	8,108	8,254	8,310	8,632	9,077	9,216	9,334	9,458	9,574	9,713	9,970
Growth Rate . . . (%)		1.7	1.8	0.7	3.9	5.2	1.5	1.3	1.3	1.2	1.4	2.6
Island Customer Coincident Peak Demand (MW)	1,691	1,716	1,756	1,773	1,803	1,923	1,942	1,972	2,007	2,036	2,067	2,115
Growth Rate . . . (%)		1.4	2.3	1.0	1.7	6.7	1.0	1.5	1.7	1.4	1.5	2.3

7 Adjusted GDP excludes production related income earned by the non-resident owners of mining, oil, and gas projects.
8 Includes Newfoundland Power and Hydro Rural.
9 Includes company use.
10 Exclusive of transmission losses and station service loads.
11 2023 Island customer coincident peak demand is an actual.

Table 5: Island Interconnected System Average Domestic Rate Forecast – Excluding HST (cents/kWh)[12]

Year	All Scenario Cases
2024	14.93
2025	16.27
2026	17.20
2027	17.67
2028	18.20
2029	18.73
2030	19.61
2031	20.59
2032	21.62
2033	22.70
2034	23.84
2035	25.03

Table 6: Island Interconnected System Cumulative EV Sales

	Slow Decarbonization Scenario		Reference Case		Accelerated Decarbonization Scenario	
	Light-Duty Vehicles	Medium- and Heavy-Duty Vehicles and Buses	Light-Duty Vehicles	Medium- and Heavy-Duty Vehicles and Buses	Light-Duty Vehicles	Medium- and Heavy-Duty Vehicles and Buses
2024	2,225	73	2,336	80	3,358	113
2025	3,203	125	3,700	152	5,625	224
2026	4,540	195	5,935	249	8,898	382
2027	6,374	279	9,350	380	13,391	670
2028	8,942	401	13,885	551	19,405	1,024
2029	12,519	579	19,478	796	27,397	1,459
2030	17,481	819	26,234	1,125	38,555	1,989
2031	24,089	1,138	34,527	1,545	53,266	2,633
2032	32,583	1,552	45,028	2,131	71,503	3,408
2033	42,975	2,057	58,227	2,832	92,445	4,331
2034	54,753	2,664	74,315	3,662	115,247	5,419
2035	68,560	3,385	93,661	4,632	150,728	6,684

[12] The rates provided herein are estimates based on assumptions made at a point in time. Actual customer rates could differ from those outlined herein for a variety of reasons, including assumptions around rate mitigation post-2030, actual customer load, rate increases associated with Newfoundland Power's costs, etc.

Attachment 2

NL EV Adoption and Impacts Study – Final Results

Dunsky Energy + Climate Advisors

April 2, 2024

newfoundland labrador hydro

NL EV Adoption and Impacts Study

Final Results

dunsky Energy + Climate

April 2, 2024


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ACCELERATING THE CLEAN ENERGY TRANSITION
ANALYSIS + STRATEGY
BUILDINGS
MOBILITY
INDUSTRY
ENERGY
19 Years
50+ Dedicated Professionals
700+ Projects across 31 States & Provinces


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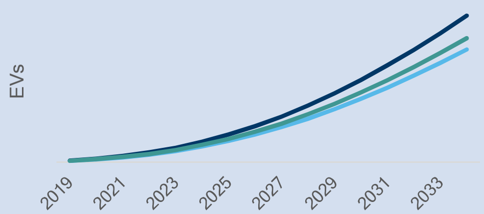
ANALYSIS + STRATEGY
BUILDINGS
MOBILITY
INDUSTRY
ENERGY
GOVERNMENTS
UTILITIES
CORPORATE + NON-PROFIT

Methodology

Approach

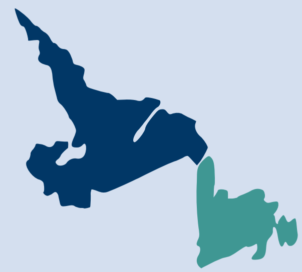
The study follows the following three steps to assess the potential impacts of EVs within Newfoundland and Labrador. Key aspects of the study approach are highlighted throughout the report.

Forecast EV Adoption



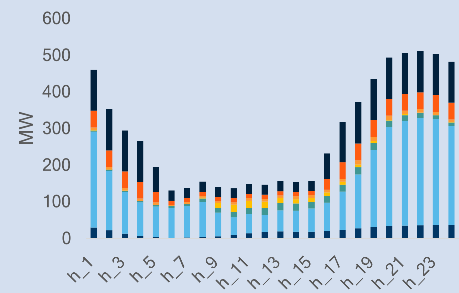
Using Dunsky's Electric Vehicle Adoption (EVA) model, forecast EV uptake within the province under various scenarios reflecting different policy, program and technology conditions.

Develop Regional Projections



Estimate EV adoption across two provincial zones based on high-impact factors likely to influence regional variation in EV adoption.

Assess Load Impacts



Assess the energy (GWh) and peak demand (MW) impacts associated with EV charging loads

Methodology

Approach: EVA Model

The study leverages Dunsky's Electric Vehicle Adoption (EVA) Model to forecast the uptake of EVs.

EVA powered by dunsky

TECHNICAL

Assess the maximum theoretical potential for deployment
- Market size and composition by vehicle class (e.g. cars, trucks, buses)
- Model availability for each vehicle powertrain (e.g. ICE, PHEV, BEV)

ECONOMIC

Calculate unconstrained economic potential uptake
- Incremental purchase cost of PHEV/BEV over ICE vehicles
- Total Cost of Ownership (TCO) (personal) or Internal Rate of Return (IRR) (commercial) based on operational and fuel costs

CONSTRAINTS

Account for jurisdiction-specific barriers and constraints
- Range anxiety or range requirements
- Public charging coverage, availability, and charging time
- Home charging access

MARKET

Incorporate market dynamics and non-quantifiable market constraints
- Use of technology diffusion theory to determine rate of adoption
- Market competition between vehicles types (PHEV vs. BEV)

Methodology

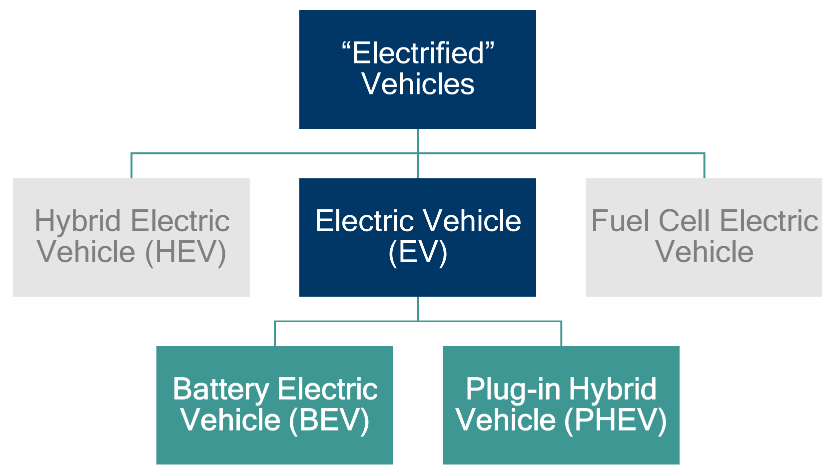
Defining Electric Vehicles

The EV analysis considers *plug-in* electric vehicles. Specifically, it considers the following vehicle types:

- **Battery electric vehicles (BEV):** "pure" electric vehicles that only have an electric powertrain and that must be plugged into an electric source to charge (*e.g.*, Tesla Model 3, Hyundai Kona, Volkswagen ID).
- **Plug-in hybrid electric vehicles (PHEV):** vehicles that can plug in to charge and operate in electric mode for short distances (*e.g.*, 30 to 80 km), but that also include a combustion powertrain for longer trips.

The following vehicle types are excluded from the analysis:

- **Hybrid electric vehicles** that do not plug in are considered internal combustion engine (ICE) vehicles.
- **Fuel cell electric vehicles** such as hydrogen vehicles where the market is assumed to be minimal in the timeframe of the study.

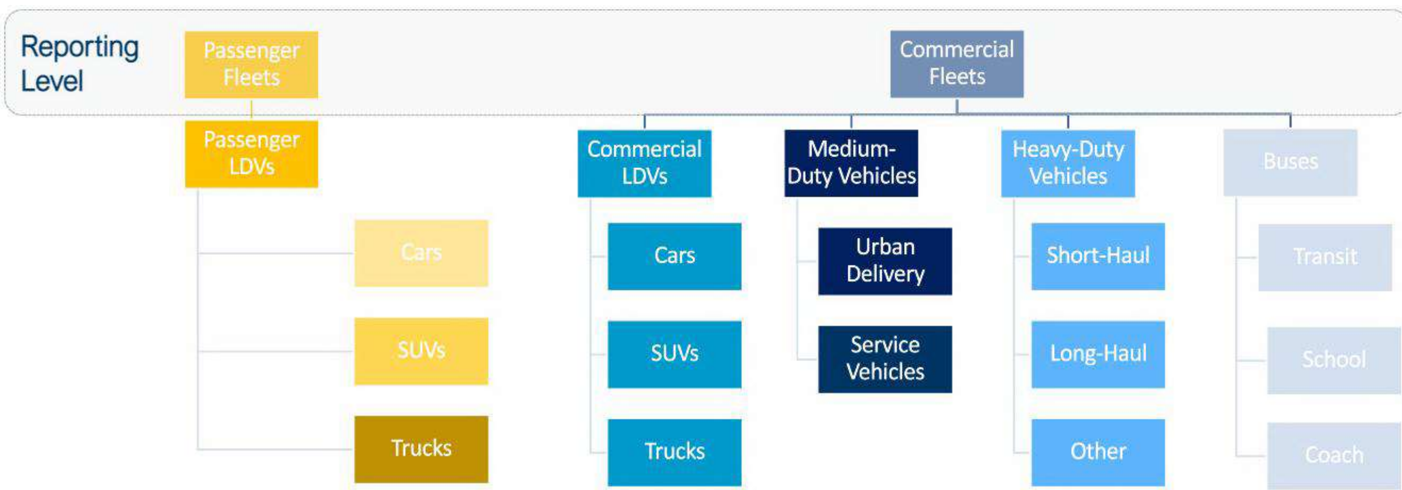


Methodology

Defining Vehicle Segments

Multiple vehicle classification systems exist, however, for the purpose of this study, we break down the on-road vehicle market into several key segments that share common characteristics

- Results are broken down into for light-, medium-, heavy- duty vehicles and buses
- More granular vehicle sub-segments were used in the modeling to capture vehicle segments with distinct factors that may impact EV adoption (e.g. limited availability of EV model, unique driving patterns or technical needs, etc.)



* The study does not model commercial light-duty vehicle segment distinctly. The analysis of light-duty vehicles focuses on the personal vehicle market (the majority light-duty vehicle market) and assumes that the commercial vehicle market follows a similar trajectory,

Electric Vehicle Forecast

Charging Load Profiles

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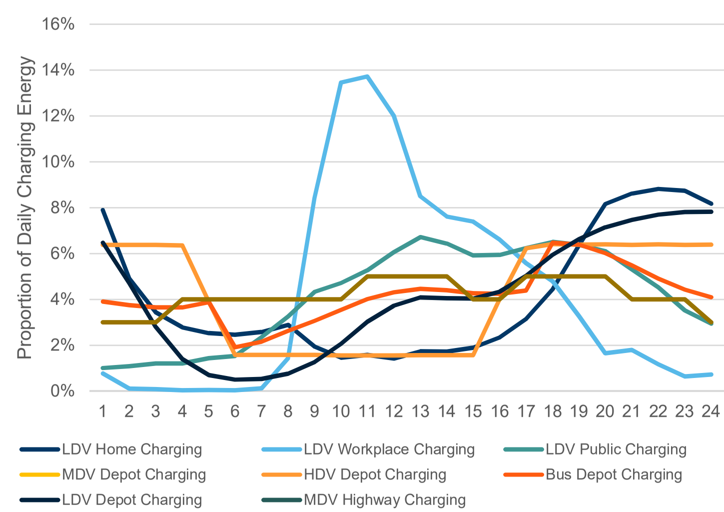
Charging event types refer to the location that charging is taking place at, which will change the power level, time of day, and flexibility of the charging load.

Charging Event Type	Passenger LDV	Commercial LDV	MDV	HDV	Bus
Home	80%	NA	NA	NA	NA
Workplace	10%	NA	NA	NA	NA
Public	10%	NA	NA	NA	NA
Depot	NA	100%	100%	100%	100%

EV load is assessed using **24-hour diversified charging distribution profiles.** The distribution profiles are then scaled to daily energy requirements for each segment.



The charging distribution profiles were developed by leveraging data sets from a range of government and utility-led pilot programs including: California Energy Commission. California Investor-Owned Utility Electricity Load Shapes; ISO New England 2020 Transportation Electrification Forecast; Rocky Mountain Institute. DCFC Rate Design Study. 2019.

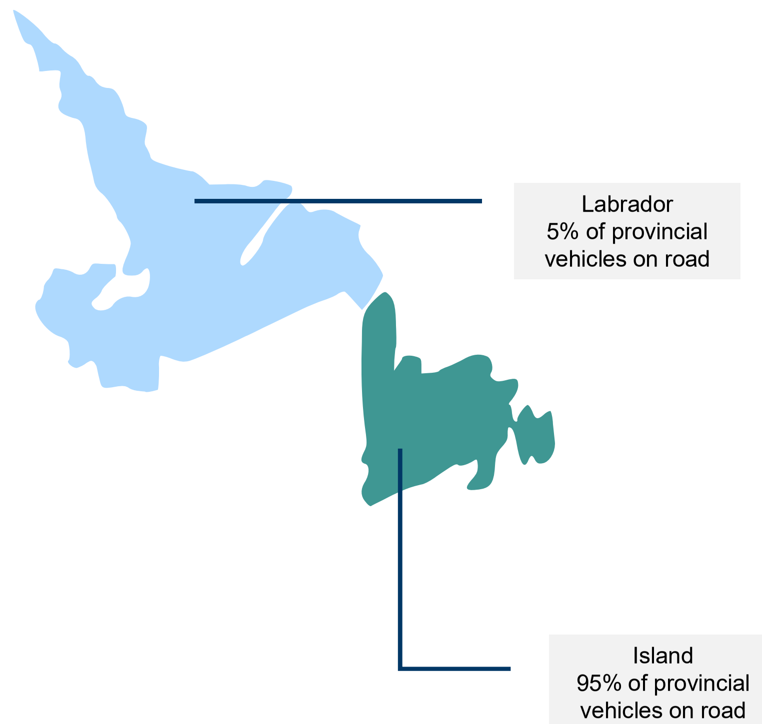
Methodology

Regional Disaggregation

The province-wide adoption forecast is disaggregated into two regions to estimate the geographic distribution of EV adoption within the province, based on five high-impact factors most likely to influence regional variation in EV uptake.

- Number of vehicles
- Historic EV sales
- Housing composition
- Income levels
- Driving distance

Data on EV annual sales and EVs on the road historically in Labrador and the Island is limited (data available at the province wide level). It is assumed that minimal EV adoption to date has occurred in Labrador to date.



Agenda

1. Introduction
2. Methodology
3. **Market Characterization**
4. Results
5. Question & Next Steps

Market Characterization

Vehicle Market

Approximately 414,000 vehicles are on the road in Newfoundland and Labrador

- Light-duty vehicles (LDVs), both personal and commercial, represent 93% of vehicles (386,000 vehicles on the road).
- Medium-and heavy-duty vehicles (MHDVs) represent the remaining 7% of vehicles (27,000 vehicles on the road).

Approximately 27,000 new LDVs are estimated to be registered annually in the region

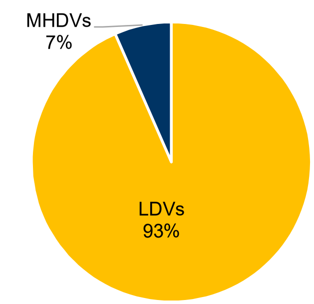
- Majority (90%) of LDVs assumed predominantly passenger/personal use, with the remaining being commercial/institutional fleets.
- SUVs and Pickups make up 80% of new vehicle sales, and 69% of vehicles currently in circulation, reflecting an ongoing trend towards SUVs and light-duty trucks.

Approximately 2,050 new MHDVs are estimated to be registered annually

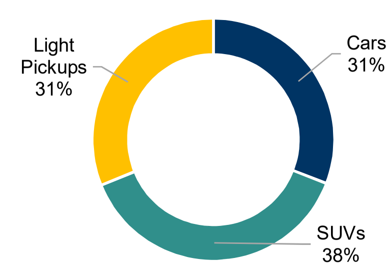
- Medium-Duty Vehicles make up 77% of MHDVs in circulation

The estimated vehicle market sizes used in the study represent the project team's best judgement based on analysis of data from NRCan's Comprehensive Energy Use Database (LDV and MHDV registrations) and Statistics Canada Newfoundland and Labrador Vehicle registrations (sub-segment percentage split).

Total Vehicles (2022)

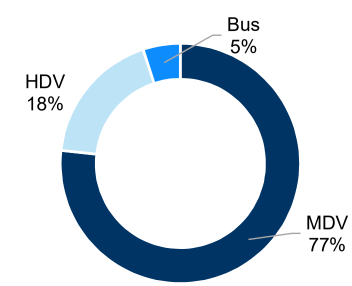


LDV Segment Split



% of Total LDVs 2022

MHDV Segment Split



% of Total MHDVs 2022

Market Characterization

Electric Vehicle Market

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EV Adoption in Newfoundland and Labrador (NL) significantly lags behind other Canadian provinces

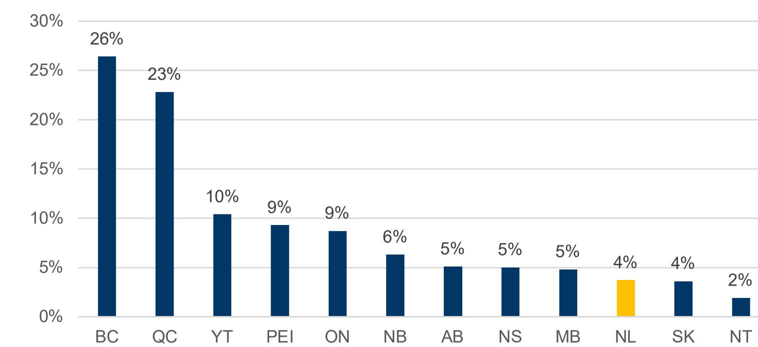
- Approximately 950 EVs registered (2022) in the province
- EVs represent 4% of new vehicle sales (2023)
    - Up from 0.3% of new vehicle sales (2020)

In NL, EV adoption increased starting in 2018 with significant jump in 2022

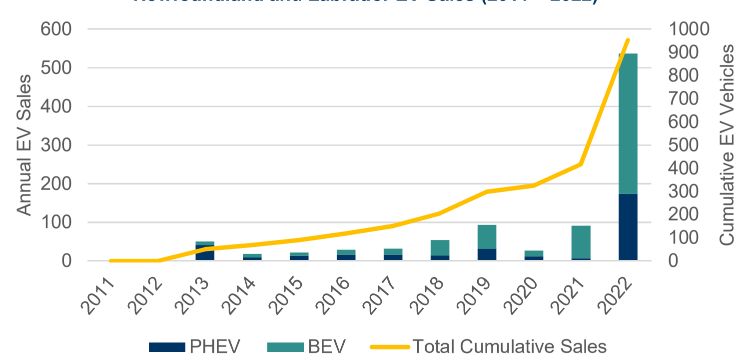
- A significant increase in uptake observed in 2018 (federal ZEV incentives began in 2019)
- Growth in BEV sales over the last 2 years (~80% BEVs)
- Limited uptake of EVs within the Medium and Heavy-Duty Vehicle (MHDV) segment

The estimated historic EV market sizes used in the study represent the project team's best judgement based on analysis of data from Statistics Canada Newfoundland and Labrador Vehicle registrations by fuel type (includes data on BEVs and PHEVs, non-plug-in hybrids are a separate segment).

Share of ZEV New Vehicle in Q3 '23 by Province and Territories[1]



Newfoundland and Labrador EV Sales (2011 – 2022)



[1] Canadian Automotive Insights: A curated collection of Canadian EV information, analysis and insights from S&P Global Mobility Q3 2023

Agenda

Overview

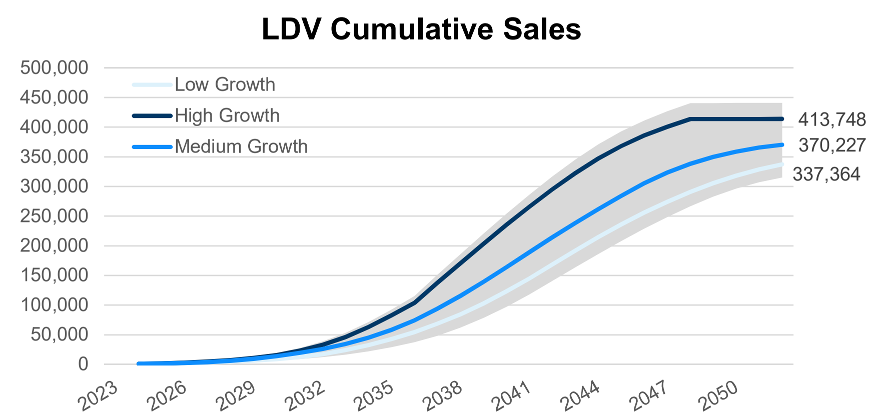
Overview

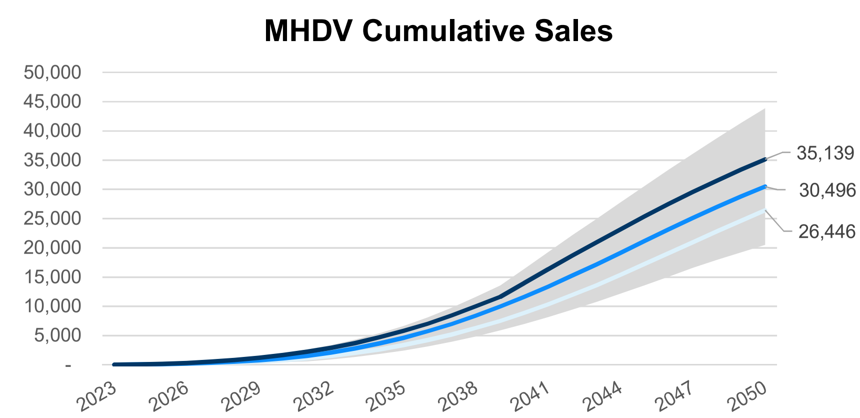
EV Adoption

The adoption of EVs in Newfoundland is forecasted to increase rapidly over the study period

However, the degree of adoption will depend on the level of policy and program interventions in place to accelerate EV adoption.

- Without significant policy and program support, EV adoption in the province will be more limited in the Low Growth scenario, reaching about 337,000 EVs by 2050.
- The Medium and High growth scenarios will reach the same level by 2047 and 2041, respectively. That's approximately 9 years earlier for the High scenario compared to the Low scenario.
- Cumulative electric MHDVs are expected to increase more rapidly after 2035, reaching 35,000 by 2050 in the High Growth scenario and 26,500 EVs on the road in 2050 for the Low Growth Scenario.





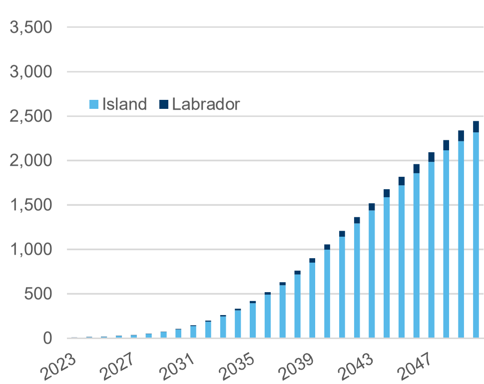
Load Impacts

Annual Load Impacts - Disaggregated

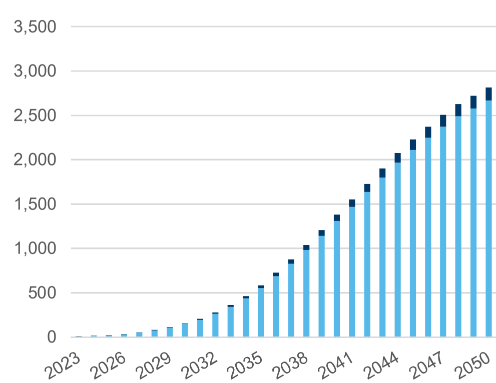
EV adoption per capita will be slightly higher in Labrador – accounting for 6% of EV GWh in 2024 despite representing only 5.2% of the provincial population. This is primarily drive by higher income and access to home charging.

Proportional EV adoption will be slightly higher in Labrador (5.2% of provincial population), accounting for ~6% of EV GWh in 2024 to ~5% in 2050. This is due to an ~ 2% higher % of fleet being EVs in passenger LDVs.

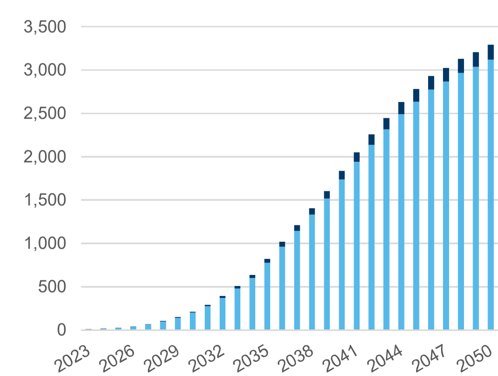
Low Growth (GWh)



Medium Growth (GWh)



High Growth (GWh)



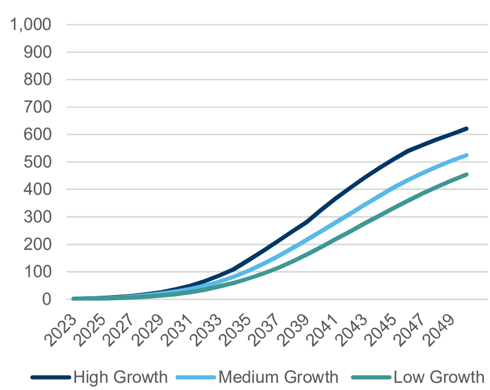
Load Impacts

Non-Coincident EV Peak Demand

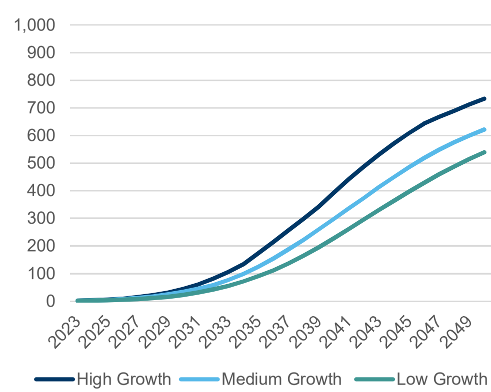
The effects of policy and technology from our scenario analysis can increase 2050 winter peak impacts from ~680 MW in the low scenario up to ~910 MW in the high scenario if no managed charging strategies are employed.

Cold winters can increase energy needs relative to summer primarily due to cabin heating requirements.[1] This accounts for the significant reduction in the EV charging peak in summer as compared to winter. The shoulder peak day lies roughly in the middle due to middle temperatures.

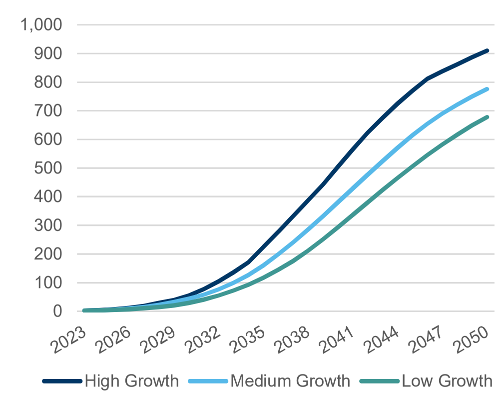
Summer Peak Day (MW)



Shoulder Peak Day (MW)



Winter Peak Day (MW)



[1] Geotab. *To what degree does temperature impact EV range?*

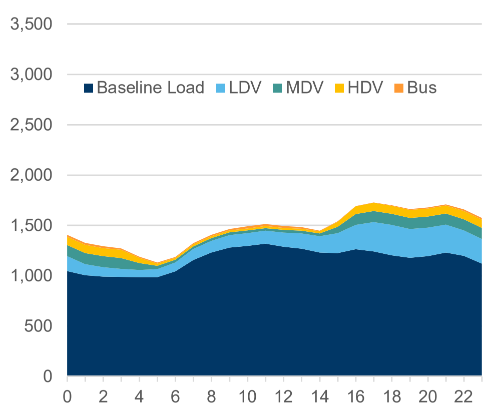
Load Impacts

EV Load Curve (High Growth, 2044) – Unmanaged

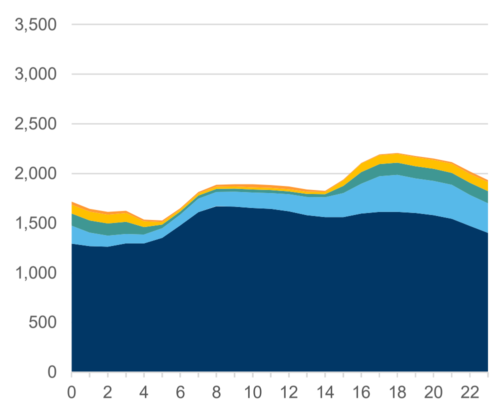
When applied to a typical peak winter day, passenger EVs will significantly increase peak demand and push the peak hour to later in the evening. This impact is primarily driven by home charging from LDVs.

If unmanaged, 2044 peak load for the NL Interconnected system in the winter (3055 MW) will shift from 6pm to 7pm (725 MW from EVs) and in summer (1728 MW) shift from 4pm to 5pm (485 MW from EVs).

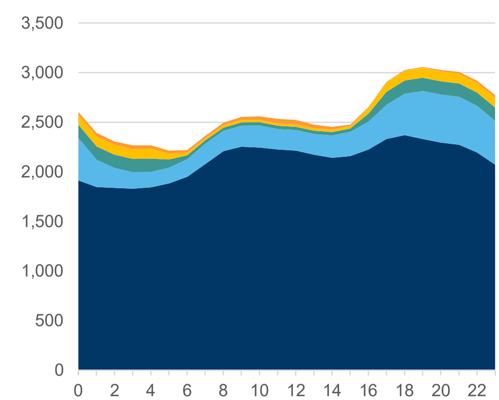
Summer Peak Day (MW)



Shoulder Peak Day (MW)



Winter Peak Day (MW)



[1] Geotab. *To what degree does temperature impact EV range?*

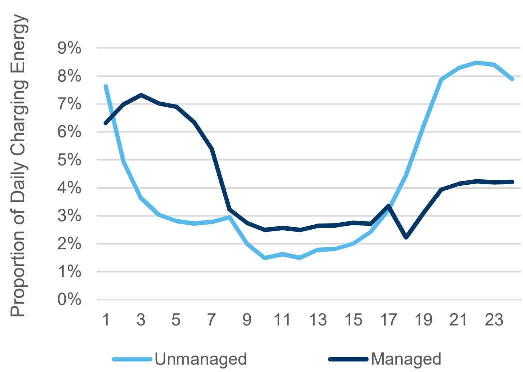
Load Impacts

Winter Peak Demand Impacts – Managed Charging

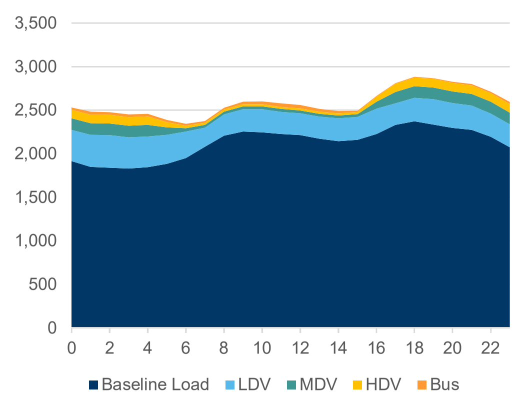
If **managed charging programs** and technologies are employed, peak load from EV charging has the potential to be reduced. The below load curve demonstrates a hypothetical managed charging scenario which assumes that only EVs which charge at home join the program, and 50% of those vehicles participate in load management on any given day.

Actual load management potential will depend highly on the local enrollment rate, incentives offered to participants, and technologies employed, but managed charging **could reduce the capacity required to serve EVs** (example below reduces 7pm winter peak in 2044 from 3055 MW to 2865 MW).

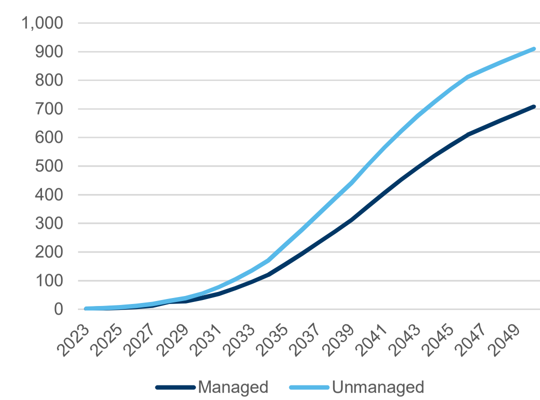
Individual Vehicle Load Curves (%)



Winter Peak Day 2044 (MW)



7pm Winter Peak Day (EV MW)

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Light-Duty Vehicles

Proposed Scenarios

Scenario Descriptions: Light-Duty Vehicles

The adoption rate of electric vehicles will be assessed under three scenarios that vary policy and program interventions.

Low Growth	**Minimal efforts to support EV adoption.** • Assumes **limited new policies and programs** are put in place to support or incentivize electric vehicle adoption
Medium Growth	**Some support to enable EV adoption.** • Assumes **stronger policies/programs** are implemented that increase the adoption of electric vehicles (additional investment in infrastructure and incentives compared to the low growth scenario)
High Growth	**Strong policy pathway to reach Federal ZEV Target.** • Assumes **stringent policies/programs** are put in place to support or incentivize electric vehicle adoption

Proposed Scenarios

Scenarios: Light-Duty Vehicles

Parameter	Scenario 1: **Low Growth**	Scenario 2: **Medium Growth**	Scenario 3: **High Growth**
Policy/Program Interventions			
Public charging infrastructure expansion	Limited *Planned investments + current growth trajectory*	Moderate *Planned investments + accelerated growth trajectory*	Significant *Keeps pace with adoption*
Vehicle incentives[1]	**BEVs:** $7,500 **PHEVs:** $5,250 *(Ramped down + phased-out by 2025)*	**BEVs:** $7,500 **PHEVs:** $5,250 *(Ramped down + phased-out by 2030)*	**BEVs:** $10,000 **PHEVs:** $7,500 *(Ramped down + phased-out by 2035)**
Existing building charging infrastructure retrofits	Limited *15% of multi-unit buildings with access to charging by 2035*	Moderate *40% of multi-unit buildings with access to charging by 2035*	Significant *90% of multi-unit buildings with access to charging by 2035*
ZEV Mandate	No ZEV mandate enforced	No ZEV mandate enforced	ZEV Mandate enforced in 2035

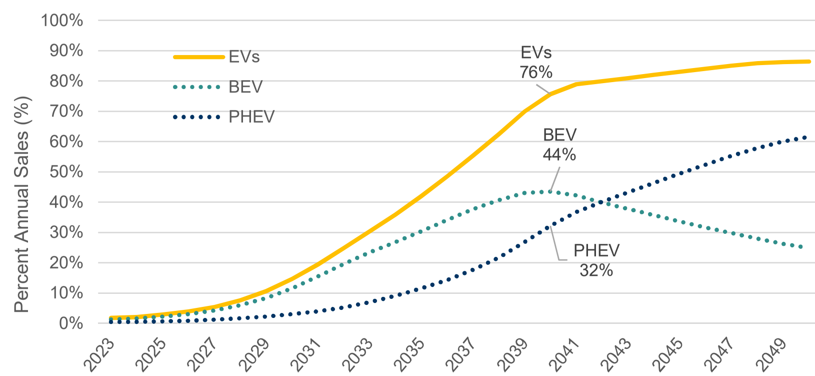
1. While significant EV incentives are unlikely through 2035, an ICE *feebate* could be put in place that penalizes carbon emitting vehicles would induce a similar financial incentive. Across all three scenarios, $150 tax per year on EV registrations will be applied starting 2025 + increase on inflation

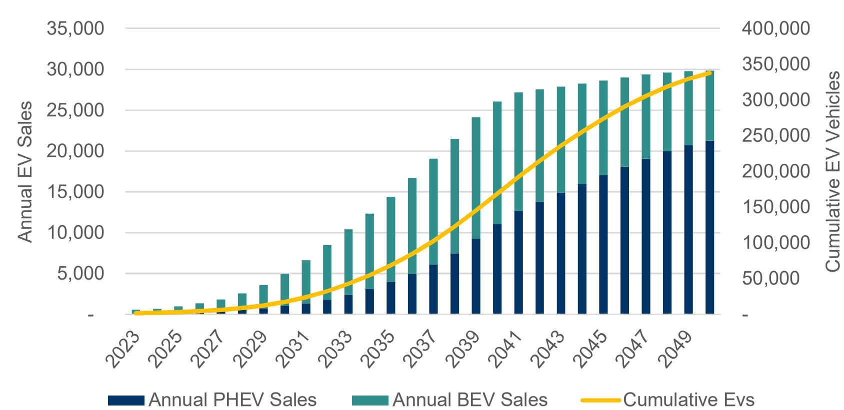
LDV Adoption

Low Growth Scenario

Under the Low Scenario, Newfoundland and Labrador will experience modest growth in EV uptake.

- By 2050, a total of 337,000 of the 414,000 LDVs on the road are forecasted to be EVs.
- EV adoption is expected to fall significantly short of federal 2035 ZEV targets (100%), reaching only 42% of new sales by 2035.
- Despite the growth in overall EV uptake, the market share shifts towards PHEVs by 2042 as public infrastructure deployment in this scenario is insufficient to meet needs of BEV drivers.



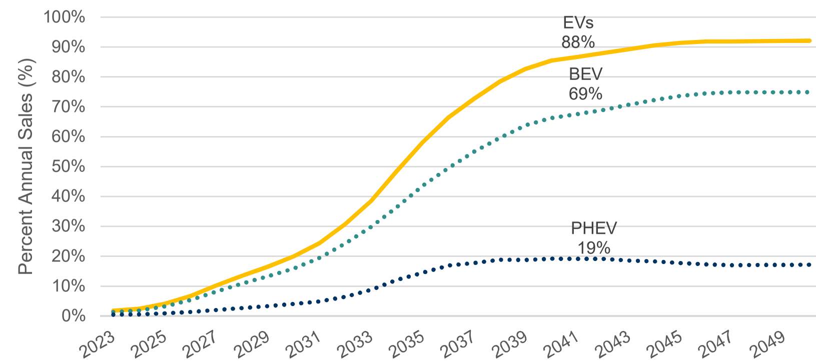


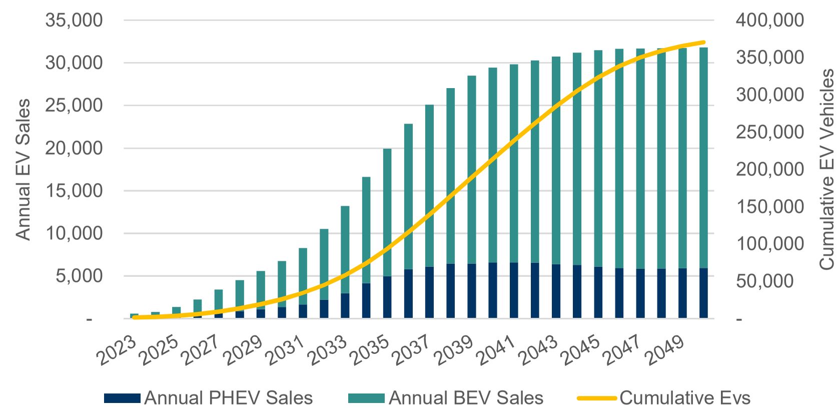
LDV Adoption

Medium Growth Scenario

Under the Medium Scenario, Newfoundland and Labrador will experience significant growth in EV uptake.

- By 2050, a total of 370,000 of the 414,000 LDVs on the road are forecasted to be EVs.
- EV adoption is still expected to fall short of federal 2035 ZEV targets (100%), reaching only 58% of new sales by 2035.
- With the more sufficient public charging infrastructure deployment assumed in this scenario, BEVs largely out-compete PHEVs due to lower total cost of ownership



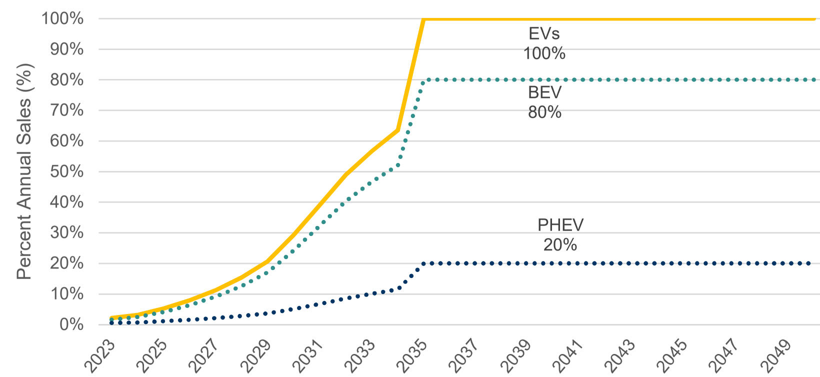


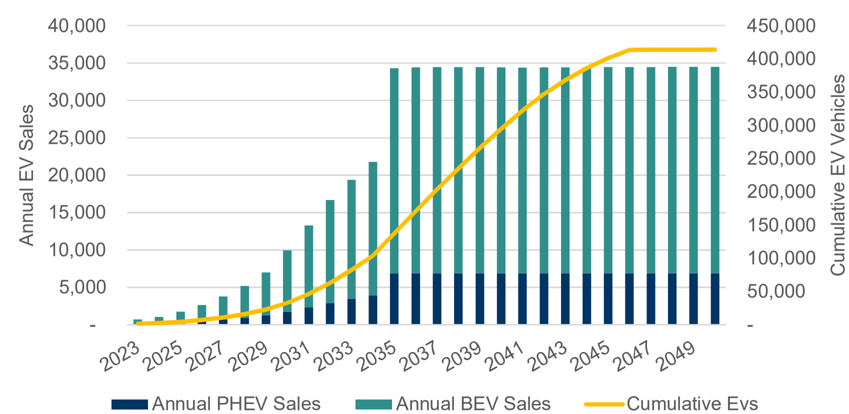
LDV Adoption

High Growth Scenario

Under the High Scenario, Newfoundland and Labrador will experience very significant growth in EV uptake.

- By 2050, almost all of the 414,000 LDVs on the road are forecasted to be Evs.
- Under the High scenario, the EV proportion of annual sales steadily increases towards the 100% ZEV mandate in 2035 due to additional policy supports including public charging, home charging access, and upfront cost reductions.
- The ZEV mandate will dramatically increase EVs on road out to 2050.





Load Impacts

LDV Load Impacts

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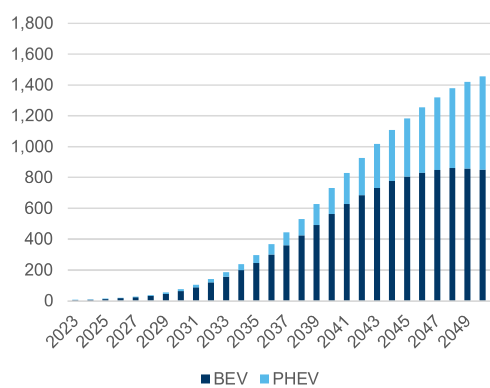
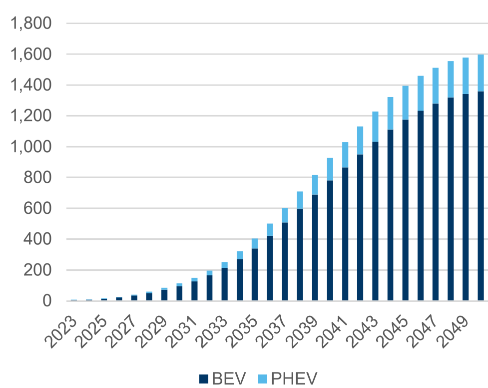
Annual load impacts could range from ~1,460 to 1,800 GWh by 2050 under the Low and High Growth scenarios, respectively, mirroring cumulative EV adoption.

The relative proportion of BEV and PHEVs adopted will also impact annual load growth, as PHEVs drive a proportion of their time on gas, whereas a BEV must always use electricity, resulting in higher energy consumption for BEVs. The breakdown of these two EV types is driven primarily by public charging availability.

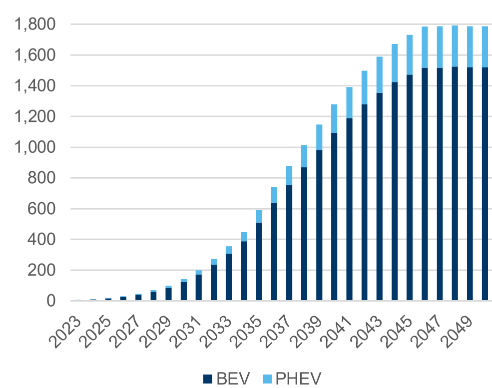
Low Growth (GWh)



Medium Growth (GWh)



High Growth (GWh)



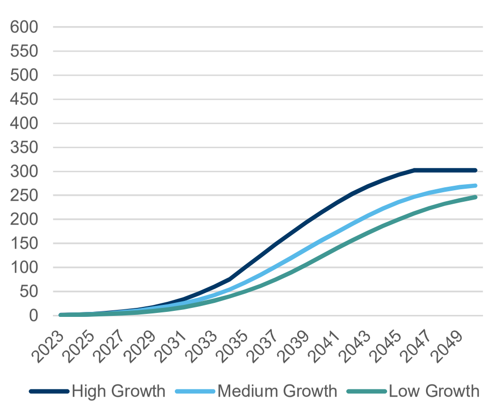
Load Impacts

LDV Load Impacts

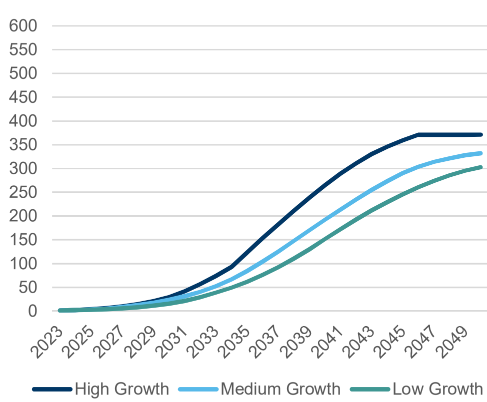
Demand impacts from unmanaged charging load will be significantly higher on a typical peak winter day relative to a peak summer day due to higher EV energy consumption in the colder months.

Outdoor air temperatures on the coldest day can increase energy needs by up to a factor of two relative to summer requirements primarily due to cabin heating requirements.[1]

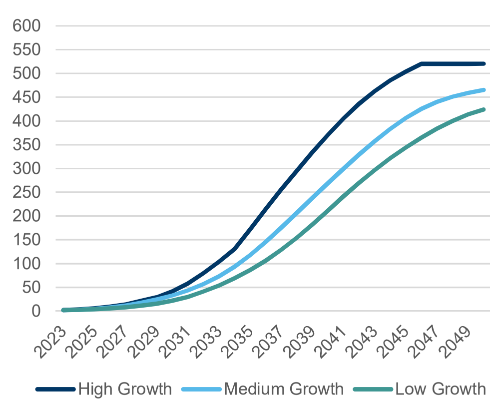
Summer Peak Day (MW)



Shoulder Peak Day (MW)



Winter Peak Day (MW)



[1] Geotab. To what degree does temperature impact EV range?

Load Impacts

Key Differences

While forecasted cumulative EVs increased in 2040 compared to the previous study, GWh from EV charging rose at a slower pace relative to cumulative EVs. However, peak demand impacts are similar between the two studies.

These effects are due to:

- A more rigorous 8760 temperature adjustment methodology resulted in a higher average vehicle efficiency
- A higher calculated average vehicle lifetime (12 years instead of 11) , based on emerging market trends

Combined, this results in 1.2 kW of peak demand impact per vehicle instead of 1.7kW in the previous study.

Vehicle	Previous Study kwh/km	Previous Study Vehicle Lifetime	kwh/km	Vehicle Lifetime
Car	0.21	11	0.18	12
SUV	0.26	11	0.225	12
Light-truck	0.29	11	0.25	12

Medium & Heavy-Duty Vehicles

Proposed Scenarios

Scenario Descriptions: Medium and Heavy-Duty Vehicles

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The adoption rate of electric vehicles will be assessed under three scenarios that vary policy and program interventions.

Low Growth	**Maintains the status quo.** • Assumes **no new policies and programs** are put in place to support or incentivize electric vehicle adoption
Medium Growth	**Moderate push for MDHV electric vehicle adoption.** • Assumes **some policies/programs** are implemented/maintained that increase the adoption of electric vehicles (additional investment in infrastructure and incentives compared to the low growth scenario)
High Growth	**Strong policy pathway for MDHV to reach Federal ZEV target.**[1] • Assumes more **stringent policies/programs** are put in place to support or incentivize infrastructure and vehicles

1. Emissions Reduction Plan released aligns with 100% of MHDV sales "where feasible" by 2040. Dunsky proposes 100% EV sales for all segments except intercity bus and long-haul trucks.

Proposed Scenarios

Scenarios: Medium and Heavy-Duty Vehicles

Parameter	Scenario 1: Low Growth	Scenario 2: Medium Growth	Scenario 3: High Growth
Policy/Program Interventions			
Vehicle incentives[1]	$75k (Ramped down + phased-out by 2026)	$75k - $200k (Ramped down + phased-out by 2030)	$75k - $200k (Ramped down + phased-out by 2035)
Public procurement targets	None	100% of new transit and school buses by 2032	100% of new transit and school buses by 2027
High power public charging for long-haul heavy-duty vehicles	Up to 350 kW charging (Varies by vehicle segment)	Up to 1 MW charging (Varies by vehicle segment)	Up to 2 MW charging (Varies by vehicle segment)
MHDV ZEV Mandate[2]	No ZEV mandate enforced	No ZEV mandate enforced	ZEV Mandate enforced in 2040

1. Low Growth scenario aligns with July 11th announcement of federal iMHZEV Program and inputs for scenarios 2 and 3 range between $75k - $200k for different vehicle segments.
2. MHDV ZEV mandate of 50% annual sales for long-haul trucking + coach buses, 100% all other segments

Medium and Heavy-Duty Vehicles

Annual Load Impacts

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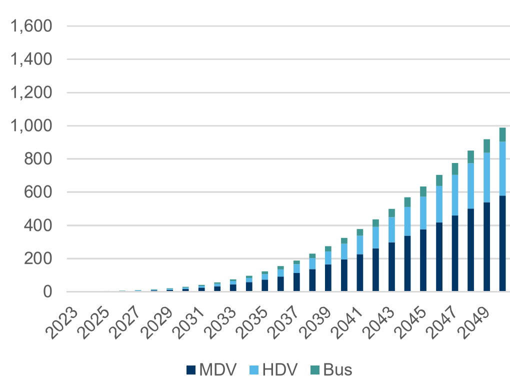
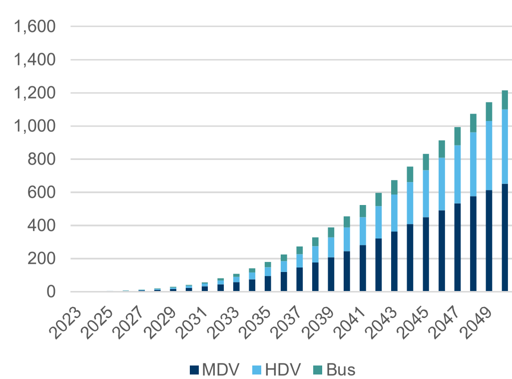
Annual load impacts could range from ~1,000 to over 1,550 GWh by 2050 under the Low and High Growth scenarios, respectively, mirroring cumulative EV adoption.

MDVs represent the largest portion of grid impacts as they are the largest vehicle segment and benefit from a strong business case for electrification resulting in a high market share for EVs.

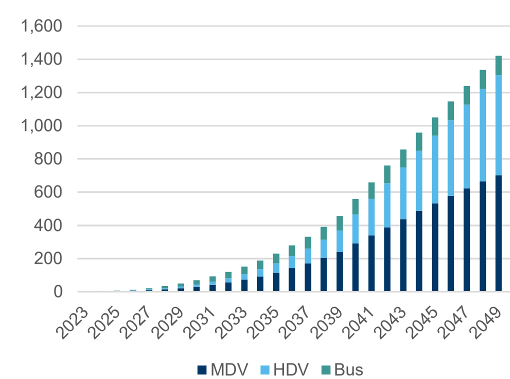
Low Growth (GWh)



Medium Growth (GWh)



High Growth (GWh)



Medium and Heavy-Duty Vehicles

Non-Coincident EV Peak Demand

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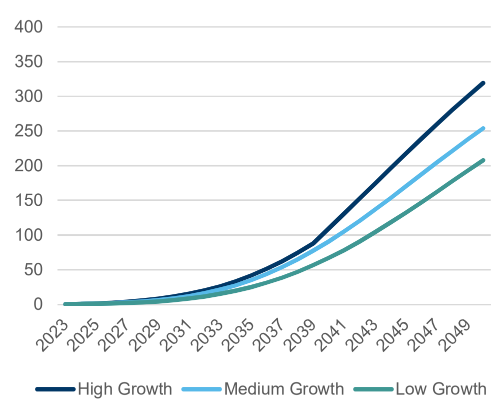
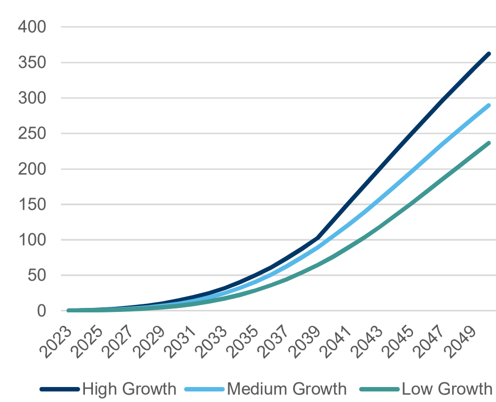
Similar to LDVs, peak impacts for MHDVs are more pronounced in winter compared to summer, which is predominantly driven by cabin heating.

However, truck cabin heating loads do not scale proportionally with overall driving energy demand as a truck cabin is only slightly bigger than an LDV's, so cold temperature impacts are not as pronounced in MDVs and HDVs as they are with LDVs and buses.

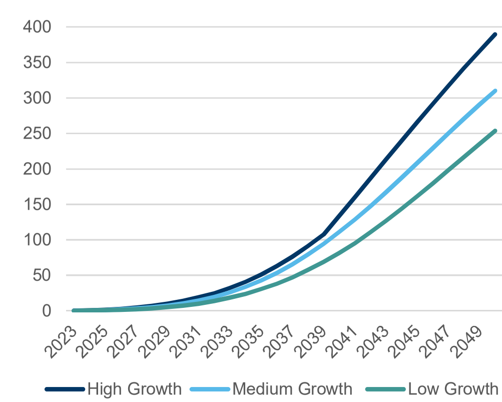
Summer Peak Day (MW)



Shoulder Peak Day (MW)



Winter Peak Day (MW)



[1] Geotab. To what degree does temperature impact EV range?

Conclusion

Electric Vehicle Forecast

Key Takeaways

EV adoption is forecasted to increase rapidly over the study period even in a Low EV adoption growth scenario. This would result in winter peak loads of at least 675 MW from EV charging alone, reaching 910 MW in the high adoption scenario. Enforcement of LDV and MHDV ZEV sales mandates at the federal level will make this high scenario much more likely.

Despite representing only 7% of the overall vehicle fleet, MHDVs will have nearly as much peak impact as LDVs due to their high energy needs. As commercial fleets electrify, new and large loads from EV charging may be harder to predict than personal LDVs without proactive engagement with commercial clients.

If managed charging programs and technologies are employed, peak load from EV charging has the potential to be reduced. Actual load shifted will depend on techniques and technologies employed, as well as incentives provided for EV drivers to participate.

Contact

Emma Hill
Principal Analyst
Emma.Hill@dunsky.com
Tel: 514-504-9030 ext. 55

Simone Hacikyan
Consultant
Simone.Hacikyan@dunsky.com
Tel: 514.504.9030 ext. 4272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Appendix

Appendix

Key Resources

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Key Data Source	Use
Natural Resource Canada (NRCan), Comprehensive Energy Use Database (CEUD) **Statistics Canada, Vehicle registrations, by type of vehicle and fuel type**	Province-wide vehicle sales and registrations, segment split (Car, Truck, SUV), EV sales
Community Accounts Unit Newfoundland and Labrador Hydro and Statistics Canada	Total Electric vehicle sales and BEV/PHEV split
Statistics Canada	Population, area of population centers, housing composition, driving distance, fuel prices
Newfoundland and Labrador Hydro	Electricity rates
Natural Resource Canada (NRCan) - Electric Charging and Alternative Fueling Stations Locator	Charging station deployment
Internal Dunsky Database	2022 vehicle cost, vehicle characteristics & projected EV model availability, battery costs

Load Impacts

Key Inputs

Vehicle	Previous Study kwh/km	Previous Study vehicle lifetime	Updated kwh/km	Vehicle Lifetime	CEUD Average Annual Driving Distance*
Car	0.21	11	0.18	12	18,200
SUV	0.26	11	0.225	12	18,200
Light-truck	0.29	11	0.225	12	18,200
MDV	0.80	16	0.80	16	26,000
HDV	1.24	20	1.24	20	120,500
Buses	1.20	16	1.20	16	54,000

*weighted averages for MDV and HDV segments reflect the sub segments that are more likely to electrify due to higher drive cycles.

Appendix

Sensitivities

The sensitivity analyses focus on technology and market uncertainty to produce upper and lower bounds for adoption. The low sensitivity is applied to the Low Growth scenario parameters while the high sensitivity is applied to the High Growth scenario parameters to create two sensitivity projections. Changes in local population are accounted for by varying the level of overall vehicle sales between sensitivities.

The results of these scenarios can be reviewed in the dashboard attached to this report.

Parameter	Low Sensitivity (Scenario 1)	Base Case Sensitivity	High Sensitivity (Scenario 3)
Technology Uncertainties			
Battery Costs	Limited cost declines	Moderate cost declines	Aggressive cost declines
EV Model Availability	Limited availability	Moderate availability	High availability
Market Factors			
Electricity Costs	Higher electricity rates	Base case rates	Lower electricity rates
Gasoline & Diesel Costs	≈ 2% per year	≈ 2% per year + $170/ton carbon tax by 2030	≈ 3% per year + $170/ton carbon tax by 2030
Vehicle Sales[1]	No growth in vehicle sales	Increase in vehicle sales to capture population growth	Higher growth than current pace

1. Includes all vehicle segments (ICE, BEV, and PHEV).

Appendix

Differences from previous project

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LDV Home Charging Access

Parameter	Scenario 1: Low Growth	Scenario 2: Moderate Growth	Scenario 3: High Growth
Home Charging Access in MURBs (previous)	0.2% (125 stalls) retrofitted per year	• 0.5% stalls retrofitted per year • 5% (in 2021) to 25% (2035) of new construction EV-Ready	• 1% stalls retrofitted per year • EV-Ready building codes starting 2026 (i.e. 100% of new construction)
Home Charging Access in MURBs (new)	Limited *15% of multi-unit buildings with access to charging by 2035*	Moderate *40% of multi-unit buildings with access to charging by 2035*	Significant *90% of multi-unit buildings with access to charging by 2035*

MHDV incentives

Parameter	Scenario 1: Low Growth	Scenario 2: Moderate Growth	Scenario 3: High Growth
MHDV Incentives (previous)	None	25% of incremental cost, up to $75k *(Ramped down and phased-out by 2026)*	50% of incremental cost, up to $150k *(Ramped down and phased-out by 2030)*
MHDV Incentives (new)	$75k (Ramped down + phased-out by 2026)	$75k - $200k (Ramped down + phased-out by 2030)	$75k - $200k (Ramped down + phased-out by 2035)

Vehicle Sales

Parameter	Low Sensitivity (Scenario 1)	Base Case Sensitivity	High Sensitivity (Scenario 3)
Vehicle Sales (previous)	Declining vehicle sales	No growth in vehicle sales	Increase in vehicle sales at current pace
Vehicle Sales (new)	No growth in vehicle sales	Increase in vehicle sales at current pace	Higher growth than current pace

* Additionally no LDV or MHDV ZEV mandates applied in previous model. Now ZEV mandates enforced in the high scenario.

Appendix

LDV: Key Inputs and Sensitivities

Battery Costs ($/kWh)[1]

	2022	2025	2030	2035	2040	2045	2050
Low	$275	$160	$80	$62	$48	$48	$48
Mid	$275	$217	$147	$99	$75	$75	$75
High	$275	$270	$209	$161	$121	$121	$121

Average Electricity Prices ($/kWh)[2]

	2022	2025	2030	2035	2040	2050
Low	$0.163	$0.168	$0.176	$0.185	$0.195	$0.205
Mid	$0.163	$0.173	$0.191	$0.211	$0.233	$0.257
High	$0.163	$0.178	$0.206	$0.239	$0.277	$0.322

Other inputs

	Value (2022)
Province Population	526,000
Population in centres with >1,000 people	385,000
Number of Population centres with >1,000 people	63
Estimated Land area of Population centres (sq. km)	4,000
Highway length (km)[3]	2,500

1. Bloomberg New Energy Finance "EV Outlook 2020" and U.S. Energy Information Administration "Annual Energy Outlook 2020". Population center inputs of the province are needed to determine the charging infrastructure needs to reach geographic coverage in the province.
2. Average electricity prices were calculated based historic delivered cost.
3. The value represents an estimate of the length of highways within the province that need to be covered by charging infrastructure deployment based on data on length of key highways, freeways, expressways and principal arterial roads.

Appendix

LDV: Key Inputs and Sensitivities

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Cumulative and Annual Vehicle Stock (Fleet) and Vehicle Sales (Rounded to Nearest 10)
(Included both passenger and commercial LDVs, with commercial fleets assumed to make up 10% of sales)

			2022	2025	2030	2035	2040	2045	2050
Low Sensitivity	Cars	Total Fleet	119,300	105,100	82,600	78,400	78,400	78,400	78,400
		New Sales	5,400	6,500	6,500	6,500	6,500	6,500	6,500
	SUVs	Total Fleet	146,900	167,800	203,500	210,500	210,500	210,500	210,500
		New Sales	14,600	17,500	17,500	17,500	17,500	17,500	17,500
	Light-Trucks	Total Fleet	120,200	113,600	100,300	97,500	97,500	97,500	97,500
		New Sales	6,800	8,100	8,100	8,100	8,100	8,100	8,100
Base Case	Cars	Total Fleet	119,300	108,500	87,000	83,600	83,800	83,900	84,000
		New Sales	5,400	6,700	6,900	7,000	7,000	7,000	7,000
	SUVs	Total Fleet	146,900	173,200	214,300	224,300	225,100	225,200	225,600
		New Sales	14,600	18,100	18,500	18,700	18,800	18,800	18,800
	Light-Trucks	Total Fleet	120,200	117,300	105,700	103,900	104,200	104,200	104,400
		New Sales	6,800	8,400	8,600	8,700	8,700	8,700	8,700
High Sensitivity	Cars	Total Fleet	119,300	111,900	91,500	88,700	89,200	89,300	89,600
		New Sales	5,400	7,000	7,200	7,400	7,400	7,400	7,500
	SUVs	Total Fleet	146,900	178,700	225,200	238,100	239,600	239,800	240,600
		New Sales	14,600	18,700	19,400	19,800	20,000	20,000	20,100
	Light-Trucks	Total Fleet	120,200	120,900	111,000	110,200	110,900	111,000	111,400
		New Sales	6,800	8,600	9,000	9,200	9,200	9,300	9,300

			2022	2025	2030	2035	2040	2045	2050
LDV Totals	Low Sensitivity	Total Fleet	386,400	386,400	386,400	386,400	386,400	386,400	386,400
		New Sales	26,800	32,200	32,200	32,200	32,200	32,200	32,200
	Base Case	Total Fleet	386,400	399,000	407,100	411,800	413,100	413,300	414,000
		New Sales	26,800	33,200	33,900	34,300	34,400	34,400	34,500
	High Sensitivity	Total Fleet	386,400	411,500	427,700	437,100	439,800	440,100	441,600
		New Sales	26,800	34,300	35,600	36,400	36,600	36,700	36,800

Source: CEUD vehicle explanatory variable tables for cars and light trucks. https://oee.nrcan.gc.ca/corporate/statistics/neud/dpa/showTable.cfm?type=CP&sector=tran&juris=nl&year=2020&rn=21&page=0

Appendix

MHDV: Key Inputs and Sensitivities

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Battery Costs ($/kWh)[1]

	2022	2025	2030	2035	2040	2045	2050
Low	$275	$160	$80	$62	$48	$48	$48
Mid	$275	$217	$147	$99	$75	$75	$75
High	$275	$270	$209	$161	$121	$121	$121

Average Electricity Prices ($/kWh)[2]

	2022	2025	2030	2035	2040	2050
Low	$0.14	$0.14	$0.15	$0.16	$0.17	$0.17
Mid	$0.14	$0.15	$0.16	$0.18	$0.20	$0.22
High	$0.14	$0.15	$0.18	$0.20	$0.24	$0.27

1. Bloomberg New Energy Finance “EV Outlook 2020” and U.S. Energy Information Administration “Annual Energy Outlook 2022”.
2. Average electricity prices were calculated based on historic delivered cost.

Appendix

MHDV: Key Inputs and Sensitivities

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MDV Cumulative and Annual Vehicle Stock (Fleet) and Vehicle Sales (Rounded to Nearest 10)

		2022	2025	2030	2035	2040	2045	2050
Low Sensitivity	Urban Delivery (Fleet)	15,840	16,640	18,340	20,210	20,610	20,610	20,610
	Urban Delivery (Sales)	1,290	1,290	1,290	1,290	1,290	1,290	1,290
	Service Vehicles (Fleet)	5,230	5,550	6,110	6,740	6,870	6,870	6,870
	Service Vehicles (Sales)	430	430	430	430	430	430	430
Base Case	Urban Delivery (Fleet)	15,840	17,040	19,230	21,700	23,130	24,310	25,550
	Urban Delivery (Sales)	1,300	1,340	1,410	1,480	1,560	1,640	1,720
	Service Vehicles (Fleet)	5,280	5,680	6,410	7,230	7,710	8,100	8,520
	Service Vehicles (Sales)	430	450	470	490	520	550	570
High Sensitivity	Urban Delivery (Fleet)	15,840	17,450	20,180	23,320	25,990	28,700	31,680
	Urban Delivery (Sales)	1,300	1,390	1,540	1,700	1,880	2,070	2,290
	Service Vehicles (Fleet)	5,280	5,820	6,730	7,770	8,660	9,570	10,560
	Service Vehicles (Sales)	430	460	510	570	630	690	760

Source: CEUD vehicle explanatory variable tables for trucks. https://oee.nrcan.gc.ca/corporate/statistics/neud/dpa/showTable.cfm?type=CP&sector=tran&juris=nl&year=2020&rn=37&page=0

Appendix

MHDV: Key Inputs and Sensitivities

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HDV Cumulative and Annual Vehicle Stock (Fleet) and Vehicle Sales (Rounded to Nearest 10)

		2022	2025	2030	2035	2040	2045	2050
Low Sensitivity	Short Haul (Fleet)	1,460	1,430	1,420	1,410	1,400	1,400	1,400
	Short Haul (Sales)	70	70	70	70	70	70	70
	Long-Haul (Fleet)	1,640	1,630	1,620	1,610	1,590	1,590	1,590
	Long-Haul (Sales)	80	80	80	80	80	80	80
	Other HDV (Fleet)	1,840	1,830	1,820	1,800	1,790	1,790	1,790
	Other HDV (Sales)	90	90	90	90	90	90	90
Base Case	Short Haul (Fleet)	1,460	1,470	1,490	1,520	1,540	1,620	1,700
	Short Haul (Sales)	70	70	80	80	80	90	90
	Long-Haul (Fleet)	1,660	1,670	1,700	1,730	1,750	1,840	1,940
	Long-Haul (Sales)	80	80	90	90	100	100	110
	Other HDV (Fleet)	1,860	1,880	1,900	1,940	1,970	2,070	2,170
	Other HDV (Sales)	90	90	100	100	110	110	120
High Sensitivity	Short Haul (Fleet)	1,460	1,510	1,570	1,630	1,700	1,880	2,070
	Short Haul (Sales)	70	80	80	90	100	110	120
	Long-Haul (Fleet)	1,660	1,710	1,780	1,860	1,930	2,140	2,360
	Long-Haul (Sales)	80	90	100	110	120	130	140
	Other HDV (Fleet)	1,860	1,920	2,000	2,080	2,170	2,390	2,640
	Other HDV (Sales)	90	100	110	120	130	140	160

Source: CEUD vehicle explanatory variable tables for trucks. https://oee.nrcan.gc.ca/corporate/statistics/neud/dpa/showTable.cfm?type=CP&sector=tran&juris=nl&year=2020&rn=37&page=0

Appendix

MHDV: Key Inputs and Sensitivities

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Bus Cumulative and Annual Vehicle Stock (Fleet) and Vehicle Sales (Rounded to Nearest 10)
(Included both passenger and commercial LDVs, with commercial fleets assumed to make up 10% of sales)

		2022	2025	2030	2035	2040	2045	2050
Low Sensitivity	Transit (Fleet)	460	460	440	430	430	430	430
	Transit (Sales)	30	30	30	30	30	30	30
	School (Fleet)	820	810	800	780	780	780	780
	School (Sales)	50	50	50	50	50	50	50
	Coach (Fleet)	90	90	110	120	130	130	130
	Coach (Sales)	10	10	10	10	10	10	10
Base Case	Transit (Fleet)	470	470	460	460	480	510	530
	Transit (Sales)	30	30	30	30	30	30	40
	School (Fleet)	830	830	840	840	870	920	970
	School (Sales)	50	50	50	60	60	60	60
	Coach (Fleet)	90	100	110	130	140	150	160
	Coach (Sales)	10	10	10	10	10	10	10
High Sensitivity	Transit (Fleet)	470	480	490	500	540	600	660
	Transit (Sales)	30	30	30	40	40	40	50
	School (Fleet)	840	850	880	900	980	1,080	1,200
	School (Sales)	50	50	60	60	70	80	90
	Coach (Fleet)	90	100	120	140	160	180	190
	Coach (Sales)	10	10	10	10	10	10	10

Source: CEUD vehicle explanatory variable tables for buses. https://oee.nrcan.gc.ca/corporate/statistics/neud/dpa/showTable.cfm?type=CP&sector=tran&juris=nl&year=2020&rn=31&page=0

Appendix A: Key Inputs and Assumptions

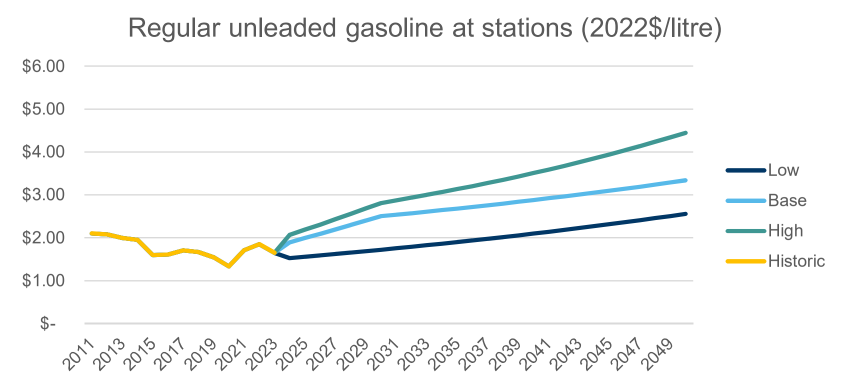
Gasoline and Diesel Rates

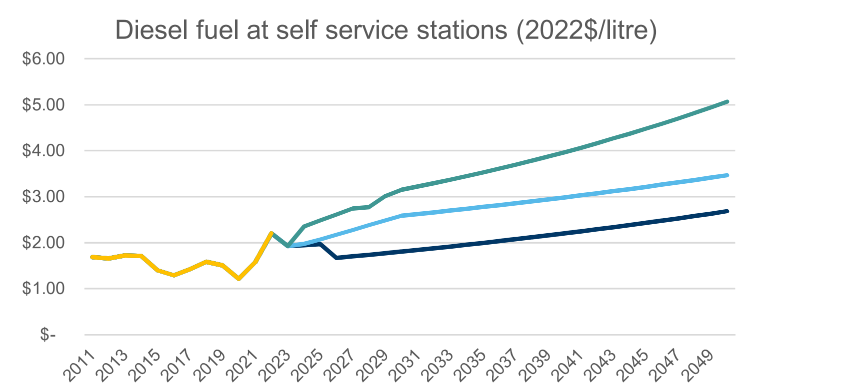
Historical retail gasoline and diesel rates have been volatile with rapid increases in the past.

The three rate scenarios attempt to capture the wide uncertainty in future prices.

Component	Lower Bound Sensitivity	Base Case	Upper Bound Sensitivity
Fuel Cost[1]	2024 price reverts to 5-year average; 2% real increase thereafter	2024 price reverts to 5-year average; 2% real increase thereafter	2024 price reverts to 2-year average; 3% real increase thereafter
Carbon tax	NA	Increases to and remains at $170 (nominal) in 2030.	Increases to and remains at $170 (nominal) in 2030.

[1] Historic St. John's rates from Statistics Canada *Monthly average retail prices for gasoline and fuel oil*





Appendix

Approach: Forecasted EV Adoption Overview

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The EVA model was applied to forecast EV adoption using the following approach:

1. **Market Characterization:** Divide the market into vehicle segments (as depicted earlier), develop representative characteristics for each segment and collect data on annual vehicle sales, fleet size and other key market inputs.

2. **Model Calibration:** Using historical inputs on vehicle sales, energy prices, vehicle costs, incentive programs and infrastructure deployment to benchmark the model to historical adoption and calibrate key model parameters to local market conditions.

3. **Scenario Analysis:** Forecast service territory-wide EV adoption under scenarios reflecting different program/policy interventions (e.g. infrastructure deployment, incentives) as well as market and technology conditions (e.g. battery costs, energy prices).

Appendix

Approach: Passenger Vehicles versus Commercial Fleets

Consideration and treatment of key barriers in the model for personal vehicles and commercial fleets reflects key differences in decision-making between the segments.

Barrier	Personal LDV	Commercial LDV	Commercial MHDV
Technical	Base vehicle assumed to be **gasoline ICEV**		Base vehicle assumed to be **diesel ICEV**
Economic	**Upfront cost and Total Cost of Ownership (TCO)**	Based **on Internal Rate of Return (IRR)** of the vehicle's upfront and operational costs over its lifetime.	
Constraints	• Range Anxiety • Charging Time • Public Charging Coverage • **Public Charging Availability** • **Home Charging Access**	• Range Requirement • Charging Time Requirement • Public Charging Coverage	• Range Requirement • Charging Time Requirement
Market	**Competition** between PHEV and BEVs		**No competition** between PHEVs and BEVs (i.e. all assumed to be BEVs)

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"NO DISCLAIMERS" POLICY

This report was prepared by Dunsky Energy + Climate Advisors, an independent firm focused on the clean energy transition and committed to quality, integrity and unbiased analysis and counsel. Our findings and recommendations are based on the best information available at the time the work was conducted as well as our experts' professional judgment. **Dunsky is proud to stand by our work.**

Schedule 4

Schedule 4

Bay d’Espoir Unit 8 Project Evidence

newfoundland labrador hydro

Contents

Appendices

Attachments

1.0 Introduction

The Bay d'Espoir Unit 8 ("BDE Unit 8") project is a critical component of Newfoundland and Labrador Hydro's ("Hydro") Minimum Investment Required Expansion Plan to ensure a reliable, cost-effective, and environmentally responsible electricity supply. BDE Unit 8 has consistently been selected as a technically viable supply option, consistent with the lowest possible cost, throughout Hydro's *Reliability and Resource Adequacy Study Review* proceeding; this has been further confirmed through the analysis presented in Schedule 3 of this application.

This project involves the addition of a 150 MW[1] generating unit to Powerhouse 2 at the Bay d'Espoir Hydroelectric Generating Facility, in addition to the facility's existing 600 MW capacity. The project leverages infrastructure built during the original construction of Powerhouse 2 in 1977, minimizing environmental impact and maximizing resource efficiency.

Through front-end planning ("FEP") and front-end engineering design ("FEED"), Hydro has developed a comprehensive project execution plan, including execution strategies in the areas of contracting, project management, construction management, project controls, health and safety, quality management and environmental management to support the project objectives and project delivery approach.

This schedule provides a description of the BDE Unit 8 project and presents evidence in support of the 2025 Build Application, detailing the project scope, procurement approach, cost, schedule, stakeholder engagement, and risk management.

2.0 Project Scope, Requirements and Activities

2.1 Project Scope

The Bay d'Espoir Hydroelectric Generating Facility as shown in Figure 1, consists of upstream storage reservoirs, a forebay, a spillway, and two powerhouses. BDE Unit 8 will supplement the existing Bay d'Espoir Hydroelectric Development, by adding a new 150 MW generating unit, increasing the overall plant capacity to 750 MW.

[1] All references to capacity are in nominal terms.

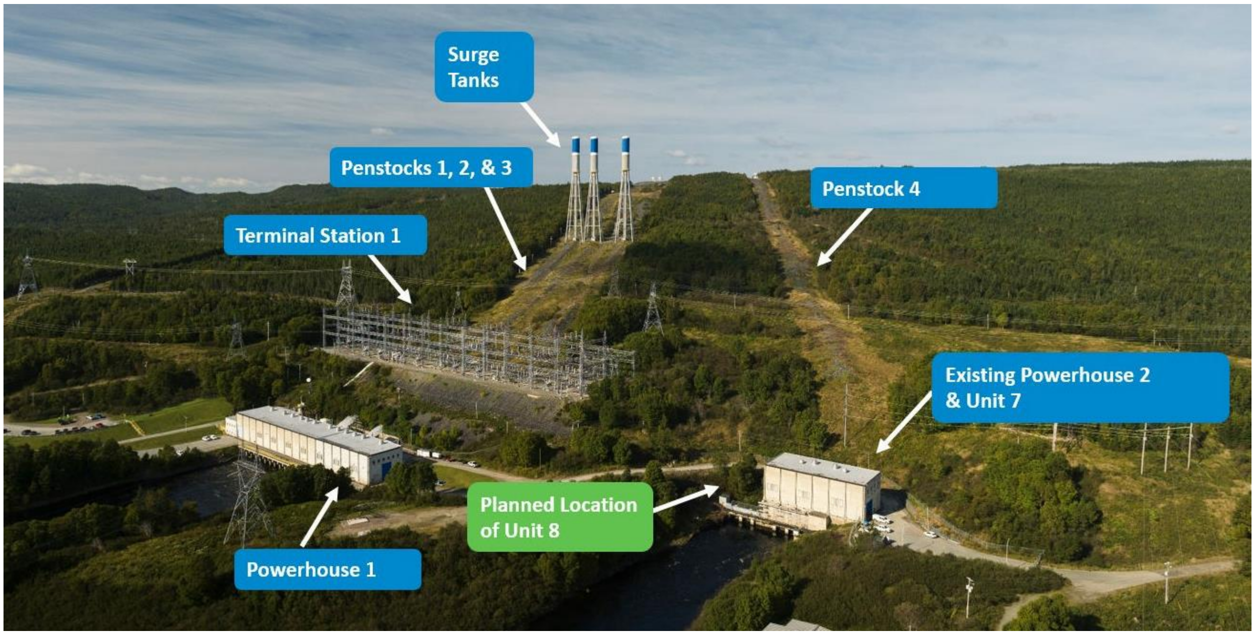

Figure 1: Bay d’Espoir Hydroelectric Generating Facility Overview

Powerhouse 1 is equipped with six generating units, each with a capacity of 75 MW, providing a combined output of 450 MW. The facility utilizes three water intakes, each connected to a penstock. These penstocks are designed to deliver water to two generating units each through a bifurcation system located near the powerhouse, ensuring the distribution of water for energy generation. The first four generating units were commissioned during Phase 1 in 1967, while the remaining two units were commissioned in 1970 during Phase 2. A single headrace canal supplies water to the three intakes, optimizing flow and maintaining steady operations. The water is then discharged through a 4.5-kilometre-long tailrace channel, which directs the flow into Fortune Bay.

Powerhouse 2 houses a single 150 MW unit (Unit 7) and receives water through a dedicated headrace canal, intake, and penstock. Its tailrace channel connects to the tailrace channel of Powerhouse 1. Commissioned in 1977 during Phase 3, the powerhouse was built with provisions for adding a second 150 MW unit (Unit 8) in the future. To minimize disruptions to Unit 7 during the eventual construction of Unit 8, rock excavation for Unit 8 was completed and the downstream portion of the draft tube, including the draft tube gate guides, was constructed. However, the headrace canal, intake, penstock, and downstream section of the tailrace channel were designed and built exclusively for Unit 7. At the time, it was anticipated that the headrace canal and tailrace channels would be expanded and new intake and penstock systems would be added during the eventual installation of Unit 8.

BDE Unit 8 is a capacity-only project that will utilize the existing Long Pond Reservoir without modification.[2] The project will therefore not require the construction of new dams or modifications to existing dams. The proposed project scope is shown in Figure 2 through Figure 6. BDE Unit 8 will include the engineering, procurement, construction, installation, commissioning, and testing of all works associated with the project, including:

- Excavation of new headrace canal;
- New intake, intake building, and ancillary services;
- New steel penstock;
- New turbine-generator (150 MW) to be installed in an extension to existing Powerhouse 2;
- New generator step-up ("GSU") transformer and isolated phase bus;
- New auxiliary mechanical, electrical, protection and control, telecontrol, and telecommunications and communications equipment;
- Extension and modifications to Powerhouse 2 to support Unit 8 installation, operation, and maintenance;
- Tailrace channel enhancements;
- A new 230 kV transmission line from the new Unit 8 GSU transformer to the existing Terminal Station 2; and
- Expansion of Terminal Station 2 to accept the new transmission line interconnection.

[2] There will be no appreciable additional system energy resulting from the proposed project.

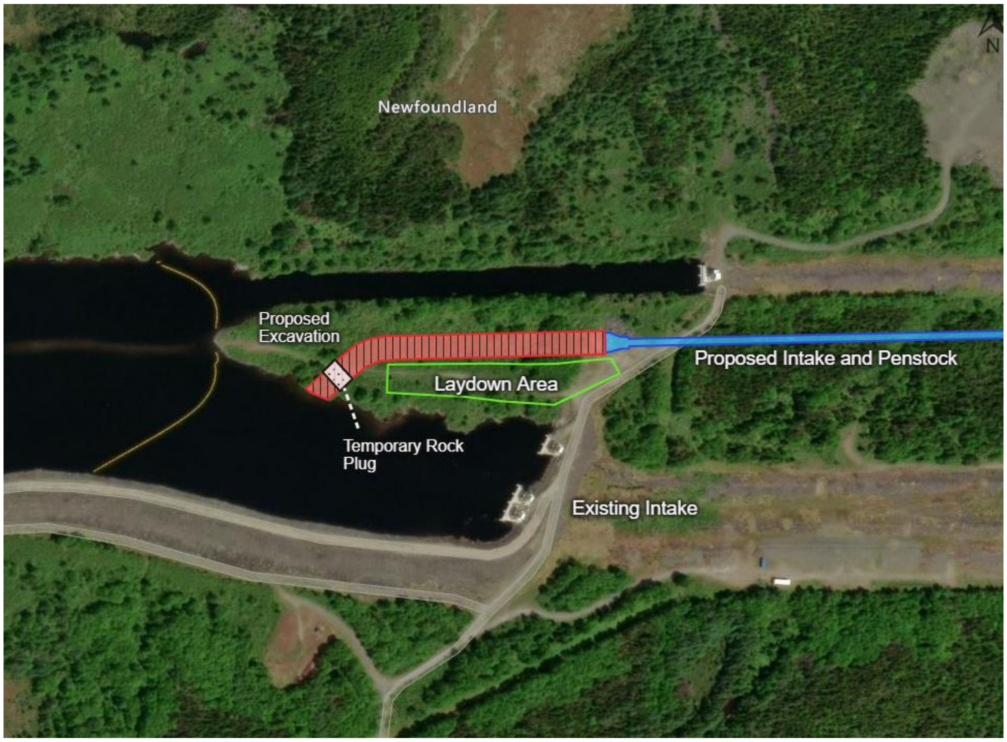

Figure 2: Headrace Canal and Intake Area

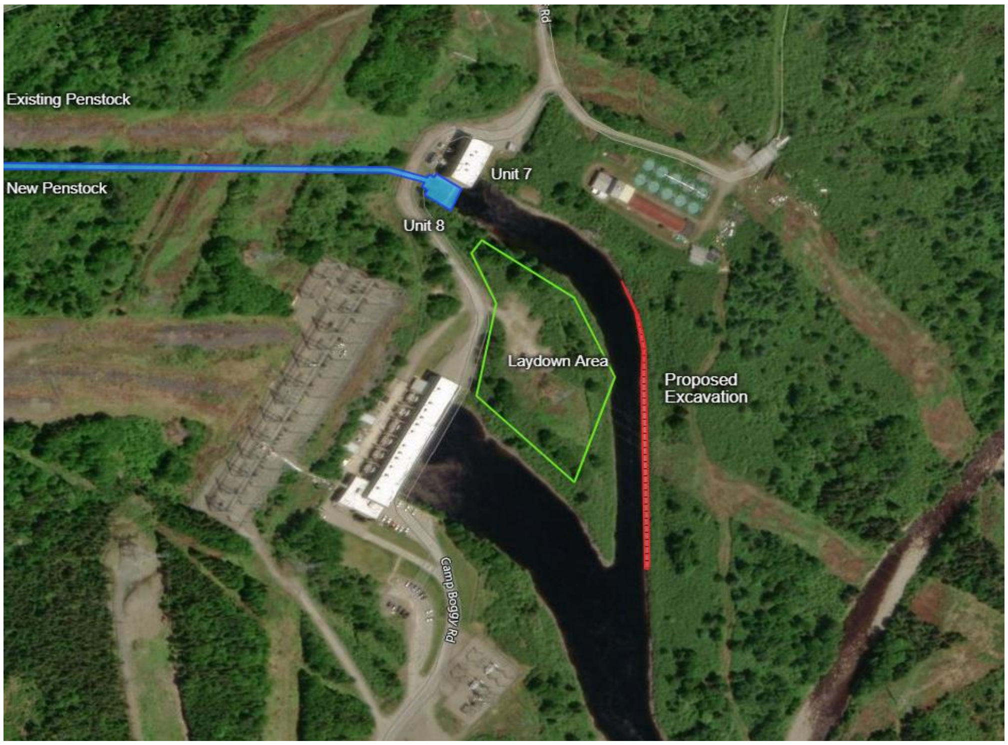

Figure 3: Penstock and Powerhouse Area

Figure 4: Transmission Line Route

Figure 5: Tailrace Widening

Figure 6: Original Powerhouse 2/Unit 7 Construction with Provision for Unit 8

2.2 Design Basis

The following subsections describe the technical and safety design requirements for key components.

2.2.1 Technical Design Requirements

Headrace Canal

- The layout will minimize impacts on existing unit operation by minimizing flow effects on the existing intakes;
- Allowable flow velocities will be within ranges that reduce the risk of frazil ice;[3] and
- The design will anticipate and facilitate methods of construction that minimize in-water work to reduce impacts on the environment and operation of other units during construction.

[3] Soft or amorphous ice is formed by the accumulation 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 and impacting the amount of water that can be drawn into the plant, thereby, reducing the generating unit capability.

Tailrace Channel

- The tailrace will be enlarged to maintain the existing operating level range, minimize head losses, and decrease any transient effects on the existing units; and
- The design will anticipate and facilitate methods of construction that minimize in-water work to reduce impacts on the environment.

Intake

- The design will meet minimum submergence requirements at minimum operating levels and full unit capacity;
- The intake will have a single intake operating gate and an upstream maintenance gate with a hoist house that will allow for full removal of the gates from their guides for maintenance without the use of a mobile crane; and
- The design life of the embedded parts will be 100 years and the design life of non-embedded structural components (e.g., gates, trash racks, etc.) and lifting devices will be 50 years.

Penstock

- The penstock will be buried steel design with varying diameters from 5.2 m at the intake to 3.76 m at the connection to the spiral case;
- The penstock will be designed to withstand the pressure increase of a load rejection without the use of a surge tank or pressure relief valve without damage or fatigue affecting its service life; and
- The design life of the penstock will be 50 years.

Powerhouse

- The new unit will be housed in a new extension to the existing Powerhouse 2 and will utilize the existing draft tube gate infrastructure that was built for Unit 8 during the original construction;
- The powerhouse extension will have its own maintenance bay similar in size to the existing Powerhouse 2 service bay;

- The rails of the existing overhead crane and draft tube deck monorail crane will be extended for use with the new unit;
- A new service elevator will be provided to facilitate construction, operation and maintenance activities for Units 7 and 8;
- Construction type and materials will be similar to the existing building including a concrete foundation and steel superstructure with concrete panel cladding; and
- The design life of the powerhouse will be 100 years.

Balance of Plant Systems

- The balance of plant systems will generally be similar to those existing in Powerhouse 2;
- Fire protection systems will be independent of existing Powerhouse 2 systems and will meet National Fire Protection Association ("NFPA") and Factory Mutual ("FM") Global Standards;
- Heating systems will utilize electric-resistance heating elements and be designed to ensure freeze protection of piping and other temperature-sensitive components during outages only;
- Ventilation systems will consist of rooftop exhaust fans with passive intake louvers and shall be sized in accordance with the American Society of Heating, Refrigeration and Air-Conditioning Engineers Standards;
- An outdoor emergency diesel generator will be provided to supply emergency and black start power to Units 7 and 8;
- Piping systems will utilize plastic and stainless steel materials wherever possible to reduce fouling and corrosion commonly incurred with the system's source water; and
- Piping systems will be selected for toughness and ease of repair and modification without the requirement for welding, proprietary systems or specialties.

Turbine

- Francis-type runner coupled to a generator by a vertical shaft, with mechanical and electrical support systems for unit operation and control;

- Runner shall be able to run continuously across the full range of intake and tailrace operating levels without damage;
- Efficiency, cavitation and vibration performance will be optimized to the planned operating regime;
- The planned operating regime will be based on the actual operating regime of Unit 7 over the past 20 years;
- The turbine and its associated draft tube shall be designed to integrate with the existing Unit 8 draft tube infrastructure; and
- The turbine will have a minimum design life of 45 years.

Generator

- The generator will be capable of being operated as a synchronous condenser;
- It will be designed to be incorporated into the existing Island transmission system and comply with the North American Electric Reliability Corporation and Hydro's standards for grid-connected generating equipment; and
- The generator will have a minimum design life of 45 years.

Excitation System

- Static type with manual and automatic modes of operation;
- Designed to satisfy the generator's excitation requirements in both generate and synchronous condense modes; and
- The exciter will have a minimum design life of 30 years.

Generator Step-Up Transformer

- Oil-filled, three-phase, 129/172 MVA, 230 kV-13.8 kV bushing-type power transformer;
- The transformer will be designed to meet current relevant industry and Hydro's standards for outdoor power transformers; and
- The transformer will have a minimum design life of 50 years.

Protection, Control and Communication Systems

- New fibre-optic line and teleprotection systems will follow Hydro's design standards;
- Communications between the generating facility and the utility will be through telecommunications protocol via a fibre-optic cable. The main communication gateway will be based on the GE-100 Remote Terminal Unit;
- Electrical devices will be protected using redundant main and backup relays;
- The design and all work for protection and control systems will comply with laws, standards and codes defined in Hydro's engineering standards and technical requirements;
- To ensure full functionality, design will ensure full compatibility and integration with existing protection, control, and communication systems where required, which include some proprietary systems;
- Communication systems will be powered by 48V DC[4] with a single backup battery bank;
- Protection, control, alarm and telemetering will be powered by 125V DC with redundant backup battery banks charged with AC[5] power from both the normal and emergency station service panels;
- Fire detection and alarm system will be designed in accordance with Hydro's standards, other standards and codes including NFPA 72, ULC-S524,[6] FM Global, and building codes;
- The fire alarm control panel will be single stage, zoned, addressable, fully supervised, software-controlled and microprocessor-based system;
- The security video monitoring system will be similar in design to the existing Powerhouse 2 system; and
- Systems will have a minimum design life of 20 years.

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[4] Direct Current ("DC").
[5] Alternating Current ("AC").
[6] Standard for installation of fire alarm systems.

Transmission Line

- The new transmission line will be a 230 kV line that will extend from Powerhouse 2 to Bay d'Espoir Terminal Station 2;
- The line route selected will minimize environmental impacts and interference with other lines;
- The transmission line will be a hybrid design of wood and steel pole construction and will be designed to all current relevant industry and Hydro standards; and
- The transmission line will have a minimum design life of 60 years.

Terminal Station Expansion

- The design will comply with all current relevant industry and Hydro standards for terminal stations;
- The design will take into consideration all known environmental, climatic, and geotechnical design conditions to ensure reliable operation throughout the design life; and
- All electrical equipment for the terminal station expansion will be designed with a minimum design life of 30 years.

2.2.2 Safety Design Requirements

The project's design will prioritize both Safety in Design[7] and overall safety by minimizing hazards and mitigating failure modes that could pose risks to workers and the public throughout the construction, operation, and maintenance phases. Considerations and safety measures taken to ensure compliance with provincial Occupational Health and Safety regulations and enhance worker safety include:

- Compliance limits of approach requirements, ensuring that all equipment layouts maintain safe distances as mandated by applicable standards and codes.
- The design will incorporate robust systems for isolation and lockout, providing mechanisms to safeguard against hazardous materials, conditions, and energy sources.

[7] Safety in Design refers to the act of putting hazard identification and risk assessment at the center of a project's design process.

- Arc flash risks will be addressed by constructing high-voltage equipment enclosures capable of containing or safely redirecting hazardous energy caused by electric faults.
- The use of hazardous materials will be minimized wherever possible, and in cases where elimination is impractical, protocols and infrastructure will ensure safe handling, transport, and disposal, reducing environmental and occupational risks.
- The design will aim to maintain noise levels at or below 85 decibels, mitigating the risk of hearing damage and ensuring compliance with noise exposure guidelines.
- To reduce the need for potentially hazardous tasks, such as confined space entry and work at heights, the design will minimize such requirements wherever feasible. For instances where these conditions cannot be avoided, the infrastructure will include fall arrest anchors, isolation points, and other features.

This holistic approach to safety design reflects a commitment to protecting workers and the public by integrating proactive measures and regulatory compliance into every aspect of the project. It is Hydro's intention to involve operations and maintenance staff throughout the project lifecycle from a planning perspective to ensure their safety considerations are met through design, construction and turnover to operations.

2.3 Project Activities

This section provides a description of the expected project activities, including design, procurement, outage planning, construction, and commissioning.

2.3.1 Design Activities

As outlined in Section 2.1, the original design of Powerhouse 2 included provisions for the future addition of Unit 8. Since then, numerous studies have been completed to refine the level of project design definition. In 2017–2018, AtkinsRéalis (formerly SNC-Lavalin) carried out a comprehensive study for Hydro on the proposed BDE Unit 8 project ("2017–2018 Study"). The scope of the 2017–2018 Study consisted of a hydraulic analysis of the conveyance system and the development of a cost estimate and project execution schedule.

The primary objective of the 2017–2018 Study was to evaluate options for adding an eighth unit to the existing Powerhouse 2. The study detailed the preferred option and laid the groundwork for future planning and project execution.

In 2023–2024, FEED was advanced to achieve the level of detail required to support the 2025 Build Application. Consultants were engaged to complete a comprehensive field investigation program including geotechnical investigations, topographic surveys, bathymetric surveys, and condition assessments of existing infrastructure. These activities were essential for understanding the current condition of the site and informing the project's design and execution planning.

Additionally, consultants were engaged to support FEP activities, ensuring alignment with the project's strategic objectives. AtkinsRéalis, building on the 2017–2018 Study, was re-engaged to further refine their earlier work. This work included the following key activities:

- Production of design and technical deliverables to a level of maturity to support an AACE[8] Class 3 cost estimate. This included design optimizations, hydraulic analysis, design drawings, design basis, specifications, flow diagrams and schematics, single-line diagrams, and general layout drawings.
- Development of Risk and Assumptions registers to identify, document and manage project uncertainties.
- Facilitation of constructability reviews to evaluate and enhance the practicality and efficiency of construction plans.
- Preparation of an AACE Class 3 cost estimate including a Basis of Estimate, provided as Attachment 1 to this schedule, and including a Quantitative Risk Analysis ("QRA") and associated Monte Carlo simulation[9] to evaluate cost uncertainties.
- Preparation of an AACE Level 3 project schedule including a Basis of Schedule, provided as Attachment 2 to this schedule, outlining a detailed timeline and critical path analysis for project execution.

[8] Association for the Advancement of Cost Engineering ("AACE").
[9] A probabilistic technique used to assess uncertainty and risk in cost projections.

This comprehensive scope of work established a robust foundation for project planning, budgeting, and risk management. The FEP activities for the project followed the Advanced Work Packaging ("AWP") approach established by the Construction Owners Association of Alberta and the Construction Industry Institute. This approach divides the project scope into logical packages. Firstly, the project area was divided into logical geographic portions of work called Construction Work Areas ("CWA"), and within each CWA, there are one or more Construction Work Packages ("CWP") that define specific scopes of work. The established CWAs and CWPs are outlined in Section 2.3.4. Each CWP then references relevant Engineering Work Packages ("EWP") that define the engineering scope needed to support construction, such as drawings, procurement details, specifications, vendor information, etc. In the execution phase of the project, an Engineering, Procurement, and Construction Management ("EPCM") consultant will complete the detailed design and prepare the necessary EWPs.

2.3.2 Procurement Activities and Early Execution

During the FEP phase, consultants were engaged to develop a contracting strategy, prepare a contract packaging plan, and identify procurement vendor packages.

Several major procurement items, including the turbine/generator and the GSU transformer packages, have been identified as being critical long-lead elements for the project due to their expected delivery time. Procurement of critical components, including the turbine and generator, has been requested in Hydro's application for early execution capital work for BDE Unit 8 and Avalon Combustion Turbine ("Early Execution Application") currently before the Board of Commissioners of Public Utilities ("Board" or "Regulator"). This will mitigate risks associated with supply chain delays and market pressures to allow for project continuity through year-end 2025, while the Board and parties consider the 2025 Build Application.

As identified in the Early Execution Application, certain advance work and analysis are required to protect the necessary timelines for construction and protect the project budget; this will mitigate the impact to ratepayers as a result of higher project costs associated with delays, and ensure project continuity through year-end 2025.

Hydro did not seek cost recovery for the expenditures proposed in the Early Execution Application. This was to allow for as expedient of a review process as possible in the interests of regulatory efficiency and minimization of increases in costs to ratepayers that would result from a delayed project in-service date.

For BDE Unit 8, these critical activities to accomplish early execution work include:

- Engage EPCM contractor to support the following activities:
  - Complete geotechnical investigations and surveys that are needed to support execution phase. Engineering and specifications for long lead or early equipment, such as Turbine and Generator Package, GSU transformer, draft tube stop logs, and 230 kV breakers; and
  - Detailed execution planning activities, such as establishing project execution plan, contracting plan, and other planning documentation.
- Engage Turbine Generator original equipment manufacturers to complete Computational Fluid Dynamics modeling and model testing. The work would also include confirmation of the final supply and install pricing and schedule.
- Complete Environmental Assessment ("EA") registration and continue with the stakeholder engagement process.

Project estimates are time sensitive and supply chain pressures continue to increase; therefore, any delay during the regulatory proceeding schedule or during project execution increases the risk of higher costs to ratepayers. Hydro's Early Execution Application was made with these risks and implications in mind.

Failure to advance these critical activities as planned in 2025 would result in a significant risk of project delays and increased costs. Additionally, the recently announced Churchill Falls Expansion and Upgrades and the Gull Island project, related to the December 2024 Memorandum of Understanding for the New Energy Partnership between Hydro and Hydro-Québec ("New Energy Partnership"), are expected to introduce market pressures on labour, engineering, equipment, and materials. Maintaining the planned schedule for the BDE Unit 8 project will minimize overlaps with these new projects, reducing the risk of cost escalation and schedule impacts due to increased competition for resources.

Continuing with this planned work will ensure that the project team remains intact and fully engaged, which will improve continuity across the project phases and enable a seamless transition into the execution phase. This continuity is crucial to maintain project momentum, effectively manage risks and ensure alignment with strategic objectives.

In the execution phase, in addition to the early execution packages, additional procurement and construction contracts will be awarded for general civil contract, transmission line interconnection, and other scope elements.

The project's procurement approach is discussed further in Section 2.7.

2.3.3 Outage Planning

During construction, there will be a need to schedule and coordinate several equipment outages. However, as provisions for the eventual construction of Unit 8 were made when Powerhouse 2 was initially constructed for the existing Unit 7, the interfaces with existing operational equipment and infrastructure is manageable. The anticipated outages include the following:

- **Transmission line construction**: A new 230 kV transmission line will be constructed, requiring crossings over/under various existing transmission lines in the area (TL204, TL231, and TL234). Each line will require a separate outage lasting approximately four to five hours, likely sequenced over one to two weeks. There is no anticipated customer impact associated with these line outages and they will follow normal equipment outage procedures.
- **Terminal station construction**: The planned extension of Terminal Station 2 to accommodate the new transmission line interconnection will require several equipment outages in the terminal station. There is no anticipated customer impact associated with these outages and they will follow normal equipment outage procedures.
- **Tailrace excavation and widening:** To minimize environmental impacts, this work is planned to occur during an extended outage of Unit 7. This will allow the work to take place when tailrace water flows are minimized. The timing of this work is flexible and can be adjusted to coordinate with the Unit 7 Life Extension project which is planned to take place during the BDE Unit 8 construction window. There is no anticipated customer impact associated with this work.

- **Services for BDE Unit 8**: Several services for BDE Unit 8 will be interconnected with the existing services in Powerhouse 2, including domestic water, wastewater, fire water, raw water, and telecommunications. These services can be connected to the existing powerhouse without interrupting operations. Minor equipment outages during installation and commissioning of the system will be managed at the contractor level.

2.3.4 Construction Activities

As previously noted, planning for the project followed the AWP approach. Using this approach, the project area was divided into logical geographic portions of work (CWAs), which contain one or more CWPs. A CWP defines a specific scope of work, such that it does not overlap with others. CWAs and CWPs represent the top levels of the Work Breakdown Structure for the project. The planned CWAs and CWPs for BDE Unit 8 are summarized below and in Table 1 and Figure 7.

CWA 1 Water Conveyance System (WCS)

This CWA encompasses the headrace canal, intake, penstock, and tailrace, including surrounding space for construction activities, laydowns, access routes, and areas for storing excavated materials.

CWA 2 Power Generation (PG)

This CWA encompasses the powerhouse facility, including the surrounding areas for access and parking lot expansion, areas adjacent to the powerhouse for the GSU transformer, and the penstock connection.

CWA 3 Transmission Line (TL)

This CWA encompasses the right-of-way for the 230 kV transmission line, which transfers the high-voltage power from the GSU transformer at Unit 8 to Terminal Station 2.

CWA 4 Terminal Station 2 Expansion (TS)

This CWA encompasses a 25-meter-wide expansion of the south side of the existing Terminal Station 2 to facilitate the installation of the terminal station equipment necessary for the connection of the new transmission line and for transfer of power to the grid.

Table 1: CWA and CWP Summary

CWA	CWP	Tag	Description
1. WATER CONVEYANCE SYSTEM (WCS)	1.1	WCS	Construction Work Area 1 - Site Preparation
	1.2	WCS	Intake Facility - Construction
	1.3	WCS	Penstock - Installation of Prefabricated Cans
	1.4	WCS	Tailrace - East Bank Widening
	1.5	WCS	Headrace Channel Section B (Rock Plug) Removal
2. POWER GENERATION (PG)	2.1	PG	Construction Work Area 2 - Site Preparation
	2.2	PG	Powerhouse Foundation - Cast-in-Place Concrete
	2.3	PG	Powerhouse Structural Steel - Supply & Erection
	2.4	PG	Powerhouse Enclosure, incl. Building M/E Systems - Supply & Install.
	2.5	PG	Powerhouse Parking Lot & Access Rd - Completion
	2.6	PG	Turbine Equipment - Installation
	2.7	PG	Generator Equipment - Installation
	2.8	PG	Auxiliary Mechanical and Electrical Systems - Installation
	2.9	PG	Generator Step-Up Transformer (GSU) - Installation
3. TRANSMISSION LINE (TL)	3.1	TL	Construction Work Area 3 - Site Preparation
	3.2	TL	Transmission Line Structures & Hardware - Installation
	3.3	TL	Transmission Line Conductor - Stringing
4. TERMINAL STATION 2 EXPANSION (TS)	4.1	TS2	Construction Work Area 4 - Site Works
	4.2	TS2	Structures - Concrete Foundations
	4.3	TS2	Electrical Equipment - Installation
	4.4	TS2	Control Building - Installation

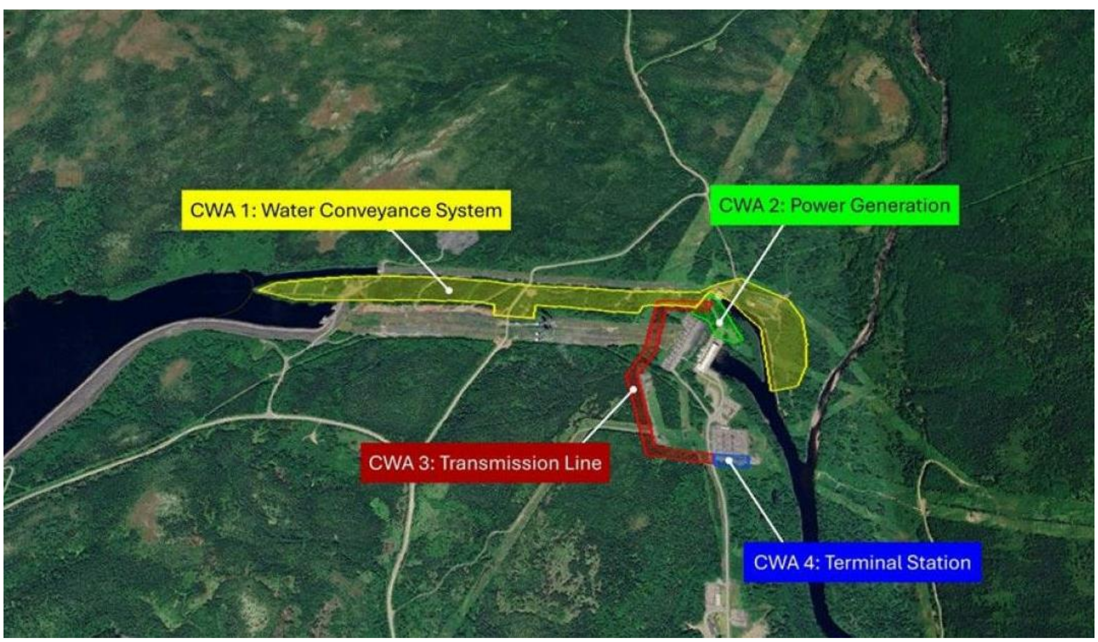

Figure 7: Proposed CWAs

The construction activities can be further described through six general construction sequences, which are outlined below, and are reflected in the project schedule. Additional schedule details are presented in Section 4.0.

Sequence 1: Early Works

- Reroute existing utilities (e.g. distribution lines, communications lines, control cables, and duct banks) out of the construction areas;
- Install construction power drops at construction work areas; and
- Transmission line structure relocation.

Sequence 2: Mobilization, Setup, and Work Area Preparation

- Construct temporary facilities, including camp accommodations;
- Prepare CWAs, laydown areas, and access roads;
- Excavate the headrace canal in the dry by leaving the rock plug in place;
- Begin powerhouse site expansion and service bay concrete works; and
- Install concrete base at powerhouse for the construction tower crane.

Sequence 3: Construction of Main Facilities

- Construct intake;
- Construct powerhouse (e.g. foundations, building enclosure);
- Construct penstock;
- Tailrace channel widening; and
- Headrace canal rock plug removal.

Sequence 4: Installation of Mechanical and Electrical Equipment

- Install turbine equipment and place secondary concrete;
- Install generator equipment;
- Install auxiliary mechanical/electrical equipment;

- Install protection, controls, and communications equipment; and
- Complete subgrade for powerhouse parking lot and access road.

Sequence 5: Installation of High-Voltage Transmission Components

- Construct 230 kV transmission line; and
- Construct Terminal Station 2 expansion.

Sequence 6: Commissioning and Completion of Overall Facility

- Cleaning, painting, and finishing of powerhouse;
- Final Commissioning, including performance testing of BDE Unit 8;
- As-built document completion, review, and acceptance; and
- Final acceptance, issue warranty certificates, and final certificate of completion.

2.4 Construction Access and Support Facilities

Planned construction access routes and construction site facilities are illustrated in Figure 8. These are located within the existing Bay d'Espoir Hydroelectric Generating Facility property boundaries.

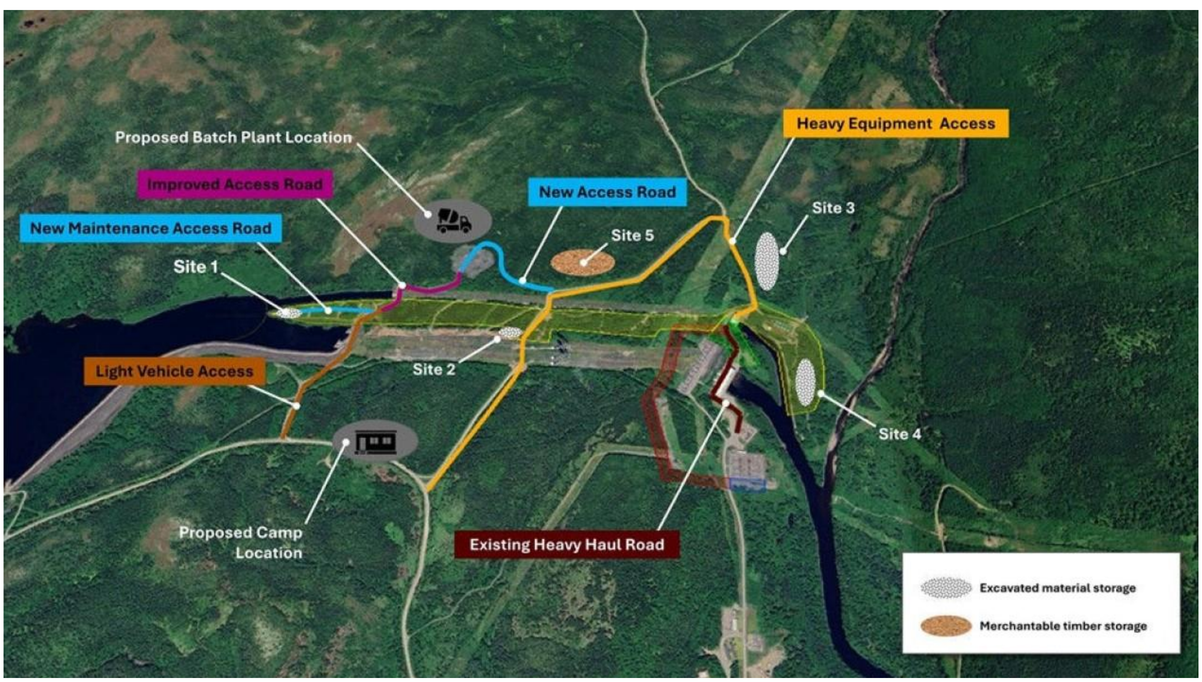

Figure 8: Proposed Access Routes and Site Layout Plan

2.4.1 Access Roads

Existing roads within the project boundaries will be utilized to facilitate construction activities:

- **Light Vehicle Access Road:** Provides access to the existing dyke and intakes but is subject to weight restrictions, making it suitable only for light vehicles.
- **Heavy Equipment Access Road:** Leads to CWA 2 and provides access to the powerhouse, supporting the transport of heavy machinery and equipment.
- **Existing Heavy Haul Road:** Serves as the primary route for transporting heavy loads, including the power transformer.

2.4.2 Support Facilities

Several dedicated sites and facilities will be established to support construction activities within the CWAs:

- **Sites 1, 2, 3, and 4:** Designated for storing excavated materials and prefabricated components, including penstock cans.
- **Site 5:** Allocated for storing merchantable timber cleared from construction zones, ensuring orderly storage and handling.
- **Concrete Batch Plant:** A proposed location is identified to support on-site concrete production, ensuring timely supply for construction needs.
- **Construction Camp:** A designated area for worker accommodations, supporting logistics and operational efficiency throughout the project.

This structured approach to site access and facility placement ensures efficient material handling, streamlined construction workflows, and optimal use of existing infrastructure.

2.5 Commissioning, Testing and Completion Activities

The commissioning, testing and completion phases of BDE Unit 8 will be managed by the EPCM contractor in alignment with Hydro's practices and processes. These phases represent critical and complex stages of project implementation, requiring coordinated efforts and collaboration from all stakeholders to ensure a successful outcome.

2.5.1 EPCM Contractor Responsibilities

The EPCM contractor will be responsible for the development of a comprehensive Commissioning Management Execution Plan that outlines the strategies for executing and managing commissioning activities, including:

- **Completions:** Ensuring all systems are ready for commissioning.
- **Commissioning Activities:** Systematic execution of commissioning processes.
- **Ready-for-Operation Verification:** Confirming operational readiness before handover.

2.5.2 Key Success Factors

The following elements are essential for effective commissioning execution:

- **Comprehensive Commissioning Plan:** Developed and agreed upon by all stakeholders.
- **Robust Safety Policy:** Adherence to a zero-harm principle for people, equipment and the environment.
- **Commissioning Schedule:** Sequenced according to the critical path, facilitating phased handover to Hydro operations of systems and areas based on ramp-up requirements.
- **Systematic Documentation Management:** Consistent and controlled documentation for commissioning activities.
- **Phased Testing Approach:** Ensuring safety of equipment and quality of completion at each stage of pre-commissioning and commissioning testing in compliance with Hydro standards.
- **Experienced Commissioning Team:** Personnel with expertise in large-scale project commissioning.
- **Proactive Problem Management:** Early identification and resolution of potential issues or delays.
- **Integrated Commissioning Approach:** Involvement of project and operations teams to support an integrated commissioning and ramp-up effort.
- **Operational Readiness Process:** A complete readiness process to facilitate the achievement of turnover milestones in an orderly and controlled fashion. Readiness for Operations shall also

have a structured process in place to verify the readiness of people, processes and systems required for turnover milestones.

2.5.3 Owner's Project Team Responsibilities

The Owner's[10] Project team will oversee and support commissioning and completion activities performed by consultants and contractors, through the following surveillance and planning activities:

- **Verification of Mechanical Completion:** Ensure mechanical completion check sheets are complete.
- **Participation in Walk-Downs:**[11] Ensure quality and readiness of installations.
- **Inspection and Testing:** Verify that all equipment is installed, adjusted, and functioning as part of the overall system to meet contract requirements.
- **Document Review:** Assess contractor quality documentation submissions where contractually applicable, such as inspection and test plans, and functional and performance test plans, for conformity with quality inspection and handover requirements.
- **Operation Validation:** Verify the satisfactory operation of the equipment as specified.
- **Documentation Handover:** Ensure that all necessary documentation/information is turned over to operations.
- **Scheduling and Coordination:** Coordination with the Commissioning team and Hydro in planning and scheduling testing activities.
- **Training and Familiarization:** Coordinate training sessions and equipment familiarization for operations personnel.
- **Tools and Spares:** Ensure delivery of required special tools and spares.
- **Operations Coordination:** Facilitate project and operations interface management.
- **Oversight and Integrity Checks:** Provide owner oversight ensuring technical design integrity.

[10] An Owner provides strategic oversight and has overall responsibility for success of a project. Hydro is the Owner for the BDE Unit 8 project.
[11] An on-site review, generally with contractor and/or other parties for the purposes of: checking completion of work; to identify readiness for testing and/or handover; and, to identify potential punch-list items.

- **Interface Management:** Facilitate project access to required operations departments and equipment.
- **System Access and Protection:** Coordinate the implementation, training and oversight of the Hydro Work Protection Code during system commissioning.
- **Handover Process:** Manage turnover of equipment to operations following commissioning acceptance of equipment, systems and/or part systems.
- **Updated Document Availability:** Ensure that all updated drawings, specifications, operations and maintenance manuals are available for the operation and maintenance of equipment.
- **Asset Management Delivery:** Organize asset management information delivery to operations.

2.6 Project Status

With reference to the Major Project phased approval process, which is illustrated in Figure 9, the project has reached the conclusion of the FEP Phase, which lays the foundation for the successful execution of major projects by ensuring sufficient work is undertaken to clearly define the need, project strategy, scope, cost, and schedule to enable well-informed decision-making early in the project lifecycle. At this stage, FEED and the associated AACE Class 3 estimate and Level 3 schedule have been completed. A decision support package outlining the project execution plan, budget, schedule, major risks and financing strategy has been presented and approved by Hydro leadership and the Board of Directors, enabling progress to the next phase contingent on approval by the Regulator.

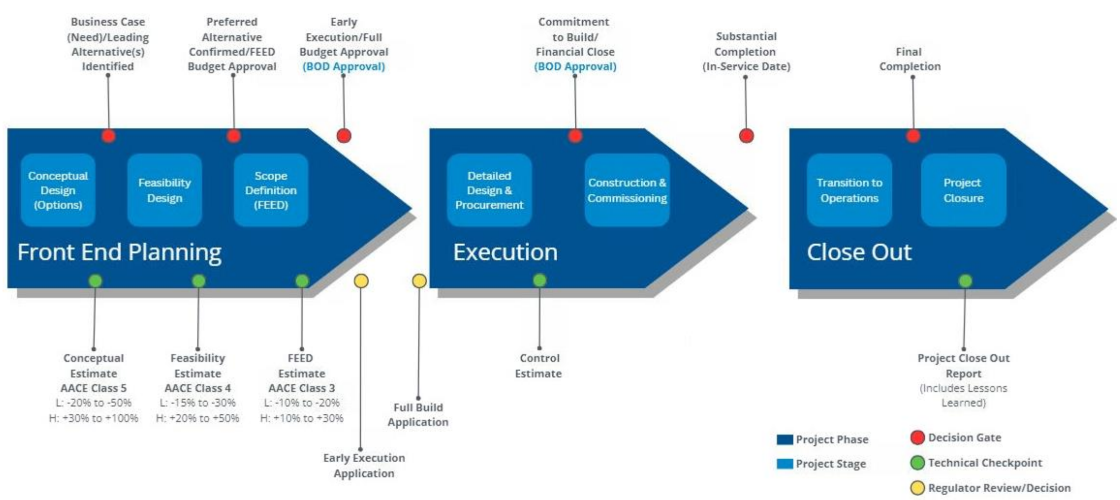

Figure 9: Major Projects Phased Approval Process

The current project status includes the completion of an internal sanction readiness review undertaken by Hydro's Internal Audit and Advisory Services department. The purpose of the review was to determine if an appropriate governance structure has been established and is effective for this project, and if Hydro had completed appropriate planning work for the 2025 Build Application from a cost, schedule and risk perspective. This review focused on three primary objectives, and aligned with the Board's capital budget requirements where applicable, including:

1) **Maturity of Deliverables for Class 3 Estimate as per AACE[12] Guidelines and associated Schedule Risk:** Ensuring deliverables are at an appropriate stage as defined for an AACE Class 3 estimate. Deliverables are categorized into scope, capacity, requirements (e.g. regulatory requirements, safety, environment), strategy (e.g. contracting), planning (e.g. permitting, work breakdown structures, schedule, stakeholder plans), studies and technical deliverables (i.e. various designs). This objective also included assessing if both planning and schedule risks are identified and mitigated.

2) **Project Management Strategies:** Assessing the application of quantitative risk assessment methodologies, including Monte Carlo simulations, to ensure comprehensive risk management and alignment to AACE Recommended Practice 40R-08 Contingency Estimating. This review also included ensuring that FEED align with AACE Recommended Practice 34r-05 Basis of Estimate, which is used to define time, resources and money required for a project.

3) **Stewardship with a Focus on Governance:** Verifying the presence of governance structures to ensure effective oversight.

The review determined that the BDE Unit 8 project documentation meets the requirements and expectations of the AACE guiding documents. The cost and schedule estimate is aligned with AACE requirements, including the BOE and the quantitative risk assessment. An appropriate governance structure has been established and is operating effectively. Internal Audit and Advisory Services concluded that various recommendations and observations that had been made throughout their review were incorporated into management's plans, as appropriate. No significant issues were identified

[12] AACE. (2012). *Cost Estimate Classification System – As Applied in Engineering, Procurement, and Construction for the Hydropower Industries,* (AACE Recommended Practice RP 69R-12).

during this process, and there are currently no outstanding issues or recommendations that would impact the 2025 Build Application.

2.7 Procurement Approach

Hydro has developed its approach to procurement for BDE Unit 8 to align with industry best practices after thorough evaluation and consideration of project execution approaches. During the FEP phase, consultants were engaged to develop a project-specific contracting strategy, including a recommended project delivery model, preparation of a contract packaging plan, and identifying procurement vendor packages. The contracting strategy is based on the outcomes of collaborative workshops to define project constraints, experiences and lessons learned from previous projects, and a general understanding of the advantages and disadvantages of various project delivery model types.

Project Delivery Model: EPCM Approach

The overarching project delivery model for this project is the EPCM approach. Under this model, the EPCM consultant will be responsible for:

- **Design Functions:** Detailed design of the project.
- **Procurement Functions:** Contract administration, expediting, logistics/transport, and material control.
- **Construction Management Functions:** Site project management, engineering, construction monitoring, and project controls.

There are five major benefits for Hydro in taking this approach:

1) Allows Hydro to form a strong Owner's team and leverage the expertise of the EPCM while retaining overall project control;
2) Empowers Hydro's team to adopt a management and oversight mandate, ensuring effective control of the EPCM consultant's performance;
3) Enables Hydro to focus efforts on owner-led core activities such as financing, procurement, EA, permitting, regulatory, and stakeholder engagement;
4) Utilizes proven systems and methods via the EPCM established systems, processes and procedures to drive efficiency and effectiveness; and

5) Provides the ability to allocate risks effectively through well-defined roles and responsibilities.

Contract Packaging Plan

The primary contract and long-lead procurement packages for the project are summarized in Table 2. While there will be additional contracts, sub-contracts, and procurement packages associated with the project, the major and long lead contracts are outlined in the table for clarity.

Table 2: Primary Contract and Procurement Package Summary

Contract/Procurement Package	Delivery/Sourcing Methodology	Scope Notes
EPCM Contractor	Hydro to specify and develop Request For Proposals package and manage contract.	EPCM Services
Heavy Civil Construction Contract	EPCM to specify and develop bid package and manage contract.	Primary construction contractor for the project responsible for construction of all temporary and permanent site facilities and procurement of specified equipment and materials other than those noted below.
Turbine Generator Supply and Install Contract	Early execution engagement with turbine generator manufacturers for pre-qualification by Hydro. EPCM to participate in development of final bid package and manage contract.	Design, manufacture, testing, delivery, and installation of Turbine Generator Package.
Transmission Line Construction Contract	EPCM to specify and develop bid package and manage contract. Hydro to complete detailed design and procure Transmission Line materials.	Construction including structure foundations, towers, hardware, and stringing.
GSU Transformer Supply	EPCM to specify and develop bid package and manage contract.	Supply of main GSU transformer. Heavy Civil contractor to install.
230 kV Circuit Breaker Supply	EPCM to specify and develop bid package manage contract.	Supply of 230 kV Circuit Breakers. Heavy Civil contractor to install.

The proposed contract packaging plan is designed to minimize interface issues that could result in legal claims regarding delays or interfaces with other contracts and/or the owner, as a result of one scope of work impeding the completion of another. It also focuses on accountability so that responsibilities are clearly defined. There are also inherent efficiencies related to securing construction labour and resources, and setup and maintenance of site services (e.g., camp accommodations, etc.).

3.0 Project Cost and Assumptions

The cost estimating structure for this project is designed to ensure financial robustness and risk preparedness.

The project Capital Cost Estimate includes the following:

- Base Cost, which includes prices for direct costs, such as equipment, materials, etc., and indirect costs, such as access roads, engineering, and temporary camps;
- Design Allowance, to account for natural changes and refinement of scope of work as engineering progresses; and
- Contingency, to account for uncertainties outside of the Hydro's control—they are the "known unknowns" that are within the project scope (e.g., geotechnical conditions).

The sum of these costs makes up the project capital cost estimate. To establish the Planned Project Budget, the following is also included:

- Interest during construction ("IDC"), to account for the cost of borrowing during project construction; and
- Escalation, which accounts for anticipated increases in labour costs and material prices over the course of the construction of a multi-year project.

The Authorized Budget, set at P85[13] confidence level in keeping with the Muskrat Falls Inquiry recommendation, encompasses the planned project budget and Management Reserve.[14] This probabilistic estimating approach ensures proper risk assessment during budgeting exercises. The use of

[13] A probabilistic cost estimate in which there is an 85% probability that the actual cost will be less than or equal to the budget.
[14] Management Reserve is an industry-standard tool that is used to manage strategic risk and to address issues that may arise that are outside of the control of Hydro. It serves as additional funds in a project budget that are set aside for strategic risks and potential external, uncontrollable factors that may arise throughout the course of the project. It is not intended to be used to accommodate foreseeable changes in scope, schedule, and cost that are within Hydro's control. Considered "unknown unknowns" that are within the project scope (e.g., government policy changes). Management Reserve is discussed further in Section 3.2.6.

a P85 estimate is consistent with Justice LeBlanc's recommendations in the final report on the Muskrat Falls Inquiry[15] and is further supported by the complexity assessment ranking of the project.

The following sections provide a detailed breakdown of each cost component.

The cost estimate was primarily developed by AtkinsRéalis, with further estimating work performed by Hydro. Further detail on estimate development is provided in Attachment 1, to this schedule.

3.1 Quantitative Risk Analysis

A QRA is defined as a "risk analysis used to estimate a numerical value (usually probabilistic) on risk outcomes wherein risk probabilities of occurrence and impact values are used directly."[16] For the BDE Unit 8 project, a QRA was facilitated by the FEED consultant (AtkinsRéalis) with participation by Hydro, as well as members of the FEED consultant design and project team.

Through the process, various elements of the estimate were reviewed by the QRA team and consensus was reached about the amount of variability that might be encountered for each element. This variability range could be for the cost of an item, or for the element of cost for the item, such as the quantity or production rates. This variability defines the probabilistic ranges that are used in the model that is used for the Monte Carlo simulation.

For example, to develop an estimate related to the excavation scope, there is an estimated quantity of material to be excavated based on the design and the known geotechnical information in the area - this is the deterministic value. During the QRA, there is an assessment of: (i) the known scope; (ii) the likelihood of further excavation required to dig deeper, or to expand the excavation, which helps to define the pessimistic variability range; and (iii) the likelihood that there may be less excavation required, which helps to define the optimistic side of the variability range. These ranges are modelled and simulated (i.e., the Monte Carlo simulation) — generally, at least 10,000 times, resulting in a statistical profile for excavation cost.

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[15] "Muskrat Falls: A Misguided Project, Commission of Inquiry Respecting the Muskrat Falls Project," The Honourable Richard D. LeBlanc, Commissioner, March 5, 2020, vol. I, Key Recommendation 5, pp. 61–62.
[16] AACE. (2024). *Cost Engineering Terminology* (AACE Recommended Practice RP 10S-90, p. 104).

This Monte Carlo simulation is done for a variety of items across the entire estimate, at the same time. The outcomes of all of these calculations and analyses provide a statistical probability curve of outcomes for the overall project. Picking a point on this curve provides the probabilistic outcome at that point, also called the P-value.

These QRA sessions collected data for the FEED consultants' cost, schedule and risk expert to model the project using an industry-standard statistical modelling tool. The output of this tool provides a range of outcomes to inform the project management team on recommended values for contingency and Management Reserve.

3.2 Estimated Amount

The capital cost estimate is based on preliminary design, conforms to AACE Class 3 cost estimate requirements, and is deemed to have an accuracy range of -20% to +30%.[17]

The Authorized Budget for BDE Unit 8 of $1.08 billion includes life-to-date costs, as well as estimated direct construction costs, indirect construction costs, contingency, escalation, IDC, and Management Reserve. Appendix A to this schedule, provides a breakdown of the project budget. Further discussion of the underlying assumptions and individual cost estimate components are provided in the following sections.

3.2.1 Assumptions

Assumptions underpinning project execution and estimating are contained in Attachment 1 and 2, the Basis of Estimate, and Basis of Schedule, respectively, to this schedule. Some of the key assumptions include:

- An adequate labour supply is available;
- Site geotechnical conditions are not materially different from what is expected;
- Existing Unit 8 infrastructure and embedded elements constructed during the original Powerhouse 2 construction are in good condition;

[17] Please refer to page 28 of Attachment 1, Basis of Estimate.

- No abnormal (i.e., outside of normal observed statistical history) weather events occur during construction;
- There will be no labour disruptions during the execution of the work; and
- Regulatory approvals, including Early Execution Application will be generally granted as assumed in the project schedule.

3.2.2 Base Cost – Direct Construction Costs

The Base Cost was primarily developed by AtkinsRéalis. This estimate was constructed using a 'bottom-up' estimate, prepared from an execution perspective, simulating the process a contractor would follow when bidding the scope.

The Base Cost was developed by dividing the work scope into CWAs, which were then further subdivided into CWPs. These are described in Section 2.3.4 of this document. The work associated with each CWP was then estimated at a detailed level, based on quantities (e.g., excavation amounts), unit prices and work crews. As the quantities are based upon a preliminary design, a design allowance was carried out to account for design maturation. The unit rate costs and crew compositions for the Base Cost were derived from comparable projects and included productivity assessments.

The Base Cost encompasses all key project phases, including estimates for:

- Design;
- Procurement;
- Fabrication;
- Manufacturing;
- Transport;
- Civil construction works;
- Equipment assembly;
- Equipment installation; and
- Testing and commissioning.

The estimate includes information from a variety of sources. Equipment, such as the turbine and generator and associated equipment, and the main GSU transformer pricing were obtained from budgetary vendor quotations. Pricing for other minor equipment was informed by recent historical data from other projects.

Certain elements of the Base Cost were estimated by Hydro, including:

- The transmission line from Powerhouse 2 to Terminal Station 2;
- Construction power drops for contractors; and
- Telecommunications integration for the new unit.

3.2.3 Base Cost – Indirect Construction Costs

Indirect construction costs[18] were estimated by AtkinsRéalis through a detailed buildup of the required equipment, facilities and support personnel based on subject matter expertise, plus allowances as deemed necessary.

Some indirect items that are included in the estimate are:

- Mobilization and demobilization;
- Freight;
- Site services, such as snow clearing, waste management, and materials handling;
- Management, overhead and administrative staff;
- Legal and insurance services;
- Temporary facilities, including setup, operation and maintenance; and
- Site access, such as walkways and staircases.

[18] Indirect costs are defined as costs not directly attributable to the completion of an activity, which are typically allocated or spread across all activities on a predetermined basis. In construction, (field) indirects are costs which do not become part of the installation, but which are required for the orderly completion of the installation, and may include, but are not limited to, field administration, direct supervision, capital tools, start-up costs, contractor's fees, insurance, taxes, etc.
AACE. (2024). *Cost Engineering Terminology* (AACE Recommended Practice RP 10S-90, p. 66).

3.2.4 Project Contingency

Contingency was estimated as part of the QRA described in Section 3.1. Further information is provided in Attachment 1 to this schedule.

3.2.5 Hydro's Indirect Costs, Escalation and Interest During Construction

Hydro's Indirect Costs

Hydro's indirect costs include the costs for the Owner's team, as well as for an EPCM consultant. The cost estimate includes labour costs as well as additional elements such as travel and accommodations within the Bay d'Espoir area, Hydro support during construction and commissioning, as well as various corporate costs, such as insurance. The estimate for the EPCM consultant was estimated by AtkinsRéalis, based on benchmarking of similar projects.

Escalation and Interest During Construction

Since the onset of the COVID-19 pandemic, escalation has been difficult to account for given the global turmoil and supply chain disruptions. There are a variety of methods that can be used to estimate escalation factors, but the primary commonality is an attempt to predict future economic and market conditions. This projection becomes increasingly difficult over longer-term periods. Hydro has developed a standardized approach to escalation projections, which is utilized on all of its projects, including BDE Unit 8. The Management Reserve does provide a mechanism to deal with a certain level of unknown market volatility that may be encountered throughout the life of the project. Further information on some of the key risks that were considered as part of the QRA can be found in Table 4 of Section 6.0.

Hydro also has a standard method of calculating IDC, which is applied to capital expenditures. Further information on Hydro's IDC assumptions is provided in Attachment 1 to this schedule.

3.2.6 Management Reserve

Management Reserve is an amount that is held outside of the performance measurement baseline for management control purposes it is reserved for unforeseen risks that is within the project scope (i.e., "unknown unknowns").[19] The Management Reserve equips Hydro to respond to strategic risks or unforeseen events quickly, consistent with recommendations from the Muskrat Falls Inquiry. Projects

[19] PMBOK Guide, p. 242.

can continue to progress and remain on schedule despite obstacles outside of Hydro's control. It is industry standard to include management reserve in project estimates especially for large complex projects, and was a key finding within the Muskrat Falls Inquiry. Commissioner LeBlanc noted that *"A reasonable reserve for strategic risk should have been included in the Project's cost estimate and made known to [the Government of Newfoundland and Labrador]."*[20] A well-managed Management Reserve is a crucial tool that increases the likelihood that the project will succeed.

During the strategic risk process, a number of strategic risks which are generally outside of the project teams' sphere of influence were considered. These include:

- Foreign currency fluctuations;
- Escalation and inflationary risks;
- Extension of the approval process;
- Availability, retention and productivity of construction labour; and
- Project coordination with an operating plant.

The Muskrat Falls Inquiry recommended that for large projects a range of cost estimates should be generated and that funding should be based on a probability of not less than 85%. The Management Reserve for the BDE Unit 8 project was calculated by determining the budget at the 85% confidence level (based on the Monte Carlo simulation conducted as part of the QRA) and subtracting the Base Cost. Further details are contained in Attachment 1 to this schedule.

Management Reserve is included within the Authorized Budget but remains outside of the project team's authorization to spend. The use of Management Reserve funds requires approval by Hydro's Chief Executive Officer.

[20] "Muskrat Falls: A Misguided Project, Commission of Inquiry Respecting the Muskrat Falls Project," The Honourable Richard D. LeBlanc, Commissioner, March 5, 2020, vol. I, Key Finding 41, p. 53.

4.0 Project Schedule

A detailed execution schedule, supported by a schedule basis, was developed during FEP by the consultant, AtkinsRealis. This schedule has been further developed and integrated with Hydro scopes, to form the overarching Project Control Schedule, provided within Attachment 2 to this schedule.

The anticipated in-service timeframe for the new BDE Unit 8 turbine is 2031. This is based on several assumptions, detailed below, including the timing of delivery of long-lead equipment.

Until the powerhouse building is erected and enclosed, the project work is seasonal in nature, once the building is complete year-round construction activity is possible. Seasonal activities are planned from April to December, with planned winter work slowdowns and stoppages of selected work. If conditions permit, the assumed seasonal execution schedule will be adjusted, as appropriate, to capitalize on favourable weather conditions. While it is possible to execute exterior civil work during winter periods, it becomes more difficult and costly, due to productivity losses, and the additional requirements for indirect work, such as snow clearing and temporary heating and lighting measures.

Once the powerhouse is enclosed, the project transitions from seasonal construction to a year-round project execution. The nature of the work also generally shifts, from civil type works to more mechanical and electrical type works.

The primary project critical path is driven by the design and modelling of the turbine and generator unit, the contract award for this unit, and the manufacturing and delivery of the unit. This delivery timeline dictates the timing for the start of onsite construction work. The secondary critical path starts with the excavation and construction of the powerhouse and the installation of the turbine-embedded parts, followed by powerhouse construction through to the enclosure when the turbine and generator can be assembled, installed and tested. The project Critical Path Schedule is shown in Appendix B to this schedule.

4.1.1 Project Major Milestones

Table 3 contains a listing of the project major milestones.

Table 3: Project Major Milestones

Milestone Description	Date
EA Registration	Q2 2025
Award EPCM Contract	Q3 2025
Build Application Approval	Q4 2025
Award Transformer Contract	2026
Final Award Turbine Contract	2027
Start On-Site Construction Works	2028
Powerhouse Enclosed	2030
Pit Free	2030
Start of Turbine Commissioning	2031
Turbine Ready for Commercial Operation	2031

4.1.2 Scheduling Constraints and Considerations

The planned work for BDE Unit 8 is subject to several constraints including approvals, equipment lead times, weather conditions, coordination with other facilities during construction, and electrical grid interactions.

Approvals

There are a number of risks that could impact the execution schedule. The project schedule assumes time for a thorough review and evaluation of the project through a regulatory proceeding necessary to obtain Board approval by the end of the fourth quarter of 2025. Hydro requested Board approval of the Early Execution Application, including procurement of critical path equipment such as the turbine and generator unit, to enable project continuity while allowing for the time necessary for the overall regulatory proceeding. Delays in receiving regulatory approval for the 2025 Build Application beyond the end of 2025 would have implications for the schedule and increase the risk of a full-year delay if Hydro cannot commence the planned seasonal construction activities as scheduled. It is projected that there will be multiple, concurrent projects with similar timelines, both internal and external to Hydro. Analysis indicates that a one-year delay in project initiation could result in a cost impact of $30 million to $50 million.

The EA release is not anticipated to be a schedule constraint, given that this is an existing brownfield site, and the EA process is planned to be completed within the 2025 Build Application review timeframe.

Equipment Lead Times

The project schedule is largely driven by the lead time for the turbine and generator, which sets the overarching timeline for the project execution. The timeline for this major component is based on budgetary quotation information. It is critical to proceed with initial vendor engagement concurrent with Board review to ensure the project remains on schedule as shown in Appendix B to this schedule, as these specialized vendors commit to schedule manufacturing of components as they accept orders.

Weather Conditions

As previously noted, a significant portion of the construction phase involves exterior civil works, which is generally planned to be executed during non-winter periods in order to manage the cost of construction execution.

Coordination with Existing Facilities

Certain portions of the planned work for BDE Unit 8 require coordination with the existing facilities located in Bay d'Espoir, most notably Unit 7.[21] As described in Section 2.3.3, the downstream tailrace widening works necessary for the BDE Unit 8 project must be executed during a period of no flow from Unit 7. While the timing of the tailrace widening work is flexible and can be adjusted to suit the timing of the outage associated with the planned Unit 7 Life Extension project ("Unit 7 Life Extension"), a more significant schedule concern exists with respect to coordinating the work at Powerhouse 2. To minimize potential productivity and schedule impacts, it is important to align the Unit 7 Life Extension work with the planned start of BDE Unit 8 construction in 2028. If the Unit 7 Life Extension work is completed prior to the end of 2028, the potential interface impacts would be minimized, as the BDE Unit 8 work would be focused outside of Powerhouse 2, while the Unit 7 Life Extension work occurs inside. Interface issues would become a concern if Unit 7 life extension were to occur in 2029, as the BDE Unit 8 Powerhouse 2 extension work would be ongoing and issues associated with work segregation; shared use of the

[21] Due to the need for regulatory approval in 2025 to align Unit 7 Life Extension with the construction of Unit 8, Hydro is planning to file a supplemental major project application for Unit 7 Life Extension in the second quarter of 2025.

overhead crane, use of lay down space, hoarding; etc. would be introduced. For these reasons, it is important to coordinate the schedules for these planned works as described herein.

Electrical Grid Interactions

Certain portions of the commissioning work for BDE Unit 8 require interaction with the electrical grid. To avoid any inadvertent impacts to the grid stability or customer supply, this commissioning is scheduled to occur outside of the winter period. In the current project schedule, the online commissioning activity is being planned to avoid grid interactions during sensitive periods. This introduces some schedule float in the phase between the powerhouse enclosure and the online commissioning but does not affect the pre-enclosure portion of the schedule, which remains constrained by its seasonal nature.

5.0 Consultation and Public Engagement

Hydro has implemented a proactive stakeholder engagement strategy for the BDE Unit 8 project, focusing on early communication, public input opportunities, and sustained collaboration throughout the project's planning, approvals, and execution phases. The primary interested groups identified for this project include Miawpukek First Nation; local municipalities, including the Town of St. Alban's and the Town of Milltown-Head of Bay d'Espoir; residents of these communities; aquaculture companies operating in Bay d'Espoir; and the member of the House of Assembly representing this district. Engagement efforts have also extended to provincial industry associations, such as Newfoundland and Labrador Construction Association, econext, and local businesses. Hydro is committed to ongoing engagement and keeping employees, the public, and other interested groups informed of progress as work moves forward. A summary of Hydro's engagement activity is provided in Appendix C to this schedule.

6.0 Risks and Risk Management

Effective risk management is critical to the success of any project. It allows Hydro to proactively identify risks that could affect the project objectives, which in turn, increases the predictability of project outcomes, helps manage complexity, helps maintain project cost, schedule, and budget, supports change management, and generally supports the delivery of the intended strategic business objectives associated with the project. For more information on how Hydro manages risk for major projects please refer to the Major Projects Governance Framework provided as Attachment 1 to Schedule 1 of this application.

During the FEP phase of the BDE Unit 8 project, a comprehensive Risk Register was developed. This document captures identified risks, their analysis, and corresponding mitigation plans.

The ongoing monitoring and refinement of this register will be critical to maintaining alignment with project goals and responding to evolving risks. By embedding risk management into all phases of the project, Hydro ensures a proactive approach toward addressing uncertainties and protecting project success.

Hydro is closely monitoring several evolving risks that have been identified in the risk management process. These include the potential impact of tariffs on material and equipment costs and foreign currency exchange rates; and the potential impacts of competing projects including the recently announced planned work related to the New Energy Partnership, which will introduce market pressures on labour, engineering, equipment, and materials. Hydro will continue to monitor these emerging risks and forecast the potential impacts throughout project execution.

Project risks have been considered in the establishment of the project budget. The identification and quantification of risk was undertaken by subject matter experts, and a QRA using a Monte Carlo simulation was employed to develop contingency and Management Reserve values which account for the risks identified. This is a prevalent methodology in project management and other disciplines for risk analysis and decision-making.

Table 4 provides a summary of the most significant project risks identified to date.

Table 4: Summary of Top Project Risks

Risk Title	Risk Description	Mitigation Notes
Supply chain pressures may increase the cost of goods and increase delivery times.	Global supply chain delays caused by global energy demand increases, green projects, etc. may impact schedule and cost. The recently announced planned work for the New Energy Partnership will introduce market pressures on labour, engineering, equipment, and materials.	• Maintain the planned project schedule. • Early procurement of long lead or critical items. • Pursue early engagement and secure manufacturing slots in advance of contract award. • Consider appropriate Management Reserve for strategic risks.
Trade disputes with the United States of America result in tariffs that cause increases in costs.	Tariffs may lead to both price increases and negative foreign currency exchange rate changes	• Established baseline foreign currency exchange rates used in QRA cost analysis. • Established baseline escalation rates due to tariffs to be used in QRA cost analysis.
Limited number of hydro turbine suppliers results in schedule delays and increased costs.	As a result of competition from other projects, there may be limited supplier resources, added complexities in the international supply chain and a potential "sellers market" resulting in higher costs, and extended delivery schedule.	• Engage with suppliers in model testing scope as soon as possible. • Enhanced oversight during the design and manufacturing process. • Engage with suppliers to explore contracting models and risk allocation strategies. • Execute procurement in Early Execution phase.
Availability of experienced contractors and retention and productivity of construction labour.	As a result of competition from other major projects, there may be limited availability of contractors with hydraulic experience and challenges recruiting and retaining experienced trades. This could impact ability to complete deliverables as per required milestones and resulting in both cost and schedule impacts.	• Early engagement of qualified contractors. • Evaluate and decide on contract package configuration. • Demonstrate that the project is required and Hydro is actively advancing regulatory processes for approval. • Provide sufficient time for bidding on the work and complete engineering before bidding. • Provide sufficient on-site oversight. • Obtain completion guarantee.

Risk Title	Risk Description	Mitigation Notes
Regulatory (Board) approval process extends beyond the assumed timeline.	If the regulatory approval process extends beyond the assumed timeline, the project schedule will be delayed and the ability to make contract commitments to support the project schedule will be impacted. This will have both a schedule and cost impact due to cost escalation and loss of project momentum.	• Produce a robust Board application and work closely with the Board during the application process. • Receive timely Board approval of Early Execution Application.
Interface risks with other work in Bay d'Espoir (Unit 7 Life Extension, Penstock Replacements, Intake work, etc.)	Other work at the BDE site may be ongoing at the same time as BDE Unit 8 construction (e.g., Penstock replacement, BDE Unit 7 Life Extension). The execution plan for BDE Unit 8 may need to change to accommodate the other planned projects. This may have impacts on cost and schedule.	• Ensure that the execution plan considers the potential impacts of other adjacent projects. • Evaluate potential synergies and opportunities. • Establish an overarching/integrated plan to identify interfaces, risks, and opportunities.
Internal decision-making process and time required.	If internal decision-making processes are not efficient, it can lead to project execution delays and schedule and cost impacts. For example, time-sensitive decisions such as awarding of contracts (e.g., equipment and construction) and proceeding with early execution. Cost impact of a one-year delay estimated at $30 million to $50 million.	• Established Project Governance structure, project steering committee, and project leadership team with clear limits of authority. • Established processes and systems to facilitate effective decision making including a review of existing authority levels. • Developing contingency plans for key personnel so decisions can be made when there are competing priorities or absences. • Corporate Interface Manager in place to manage all interfaces between Major Projects and Corporate Groups.
Failure to complete early execution.	Early execution will provide risk mitigation by maintaining the overall project schedule and budget that were established during FEED. If planned early execution is not advanced as planned, the overall project will be delayed and project costs will increase.	• Sought approval to proceed with required early execution to maintain the current project schedule.

Risk Title	Risk Description	Mitigation Notes
Coordinated use of Powerhouse 2 overhead crane.	An overhead crane is needed for elements of the BDE Unit 8 construction. If an emergency or unscheduled need for the crane to support the operation of Unit 7 arises, Unit 8 construction work could be delayed.	• Establish and interface with operations to limit impacts should this risk materialize. • Evaluate the use of a mobile crane in the powerhouse for Unit 7 response.
Adverse Weather Conditions	Weather patterns outside of the statistical norms for the area could adversely affect construction, particularly in the pre-enclosure portion of execution. These conditions may not only cause delays but also increase costs due to the need for additional measures such as heating, snow removal, or temporary structures.	• Maintain the planned project schedule. • Consider appropriate contingency for weather risks.

7.0 Conclusion

The BDE Unit 8 project is a critical component of Hydro's plan to ensure future supply adequacy for the Island interconnected System. It will allow for the retirement of aging thermal assets, support system reliability, and have supply in place to meet load growth. Hydro is recommending the addition of a new 150 MW unit at the Bay d'Espoir Hydroelectric Generating Facility, as BDE Unit 8 was consistently selected as one of the preferred, least-cost, environmentally responsible resource options, and is a significant first step in meeting the electricity demands of both the Minimum Investment Required and Reference Case scenarios.

The project is recommended to proceed under an EPCM delivery model to balance Hydro's oversight with external expertise. This approach helps to ensure effective risk management, coordination, and the successful delivery of all phases, from design to commissioning. The current project schedule assumes project completion in 2031. To allow for a fulsome review of this application while maintaining the project schedule, Hydro has filed an Early Execution Application to continue the advancement of procurement of critical components, including the turbine and generator that will mitigate risks associated with supply chain delays and market pressures.

The planning, construction, and integration of new generating resources will take years, underscoring the need for expedient action. Project estimates are time-sensitive and supply chain pressures continue to increase; therefore, any delay during the regulatory proceeding schedule or during project execution increases the risk of higher costs to ratepayers.

The Authorized Budget of approximately $1.08 billion for the project, set at a P85 confidence level, ensures an 85% probability of staying within budget, balancing cost efficiency with prudent risk management, consistent with Justice LeBlanc's recommendations in the final report on the Muskrat Falls Inquiry. Hydro has assembled an experienced Major Projects department that has the necessary expertise to execute these large-scale projects. Hydro is confident in its ability to deliver BDE Unit 8, utilizing lessons learned from previous experience, recommendations from the Muskrat Falls Inquiry, and a robust risk management strategy to mitigate risks to project cost and schedule.

Appendix A

Project Budget Breakdown

Bay d’Espoir Unit 8

Redacted

Appendix B

Critical Path Schedule

Redacted

Appendix C

Bay d'Espoir Unit 8 Engagement Summary

1.0 Introduction

For both the proposed projects in the 2025 Build Application, Hydro established objectives for engagement and information-sharing, including keeping local municipal governments, community residents and businesses, and other interested groups informed; providing public information and feedback opportunities; and establishing a channel for ongoing communication and collaboration as projects continue through planning, approvals, and execution. This engagement was initiated with primary interest groups early in the project planning phases, and well in advance of the regulatory approval process and EA registrations.

2.0 Building on Reliability and Resource Adequacy Insights

This project-specific engagement builds on the previous digital engagements of customers conducted as part of the *RRA Study Review*, which provided useful insights early in the process. In particular, input gathered from the 2024 digital engagement highlighted that customers in this province place the highest value on affordability first, then ensuring continued reliability when making decisions on what new electricity projects to pursue and invest in. Further, they prioritize lower electricity costs before investment in increased reliability or renewable technologies. In fact, the digital engagement results found that the source of electricity is a relatively lower priority for customers when compared to cost and reliability.

3.0 Early Engagement of Interested Groups

Engagement on the 2025 Build Application projects began early in the planning stages. Hydro gathered feedback and insights from communities and other interested groups primarily through:

1) Meetings and briefings with key groups with interest in the respective projects;
2) Community "open house" information sessions held in the proposed project locations, aimed at informing local residents and inviting their feedback; and
3) Public comments and questions were also accepted via email.

Hydro has been sharing information with the public and other interested groups, engaging and meeting face-to-face in the communities in which it operates. From the early project planning phases, Hydro has met with Town Councils and senior staff in Milltown-Head of Bay d'Espoir and St. Alban's, as well as with Miawpukek First Nation.

Hydro is committed to ongoing engagement and keeping our employees, the public, and other interested groups informed of progress as work moves forward. Hydro will continue to gather input throughout via the EA and regulatory application processes, and during the construction execution, commissioning and start-up phases.

4.0 Bay d'Espoir Unit 8 Project

Early outreach and engagement on the Bay d'Espoir Unit 8 project began in late 2023 with Hydro meeting in-person with Town Councils for Milltown-Head of Bay d'Espoir and St. Alban's, as well as with Miawpukek First Nation's Chief and Council. In addition, the area Members of the House of Assembly for the District of Fortune Bay-Cape La Hune has been informed of project details, status, and community outreach activity. Engagement with the Towns continued through 2024 with project planning updates via email as well as additional meetings with Councils.

These early meetings were valuable in terms of providing planning-stage information to local Town officials, gathering initial reaction and feedback, and understanding key interests and issues.

In March 2025, open house information sessions for local residents and businesses were held in St. Alban's and in Milltown-Head of Bay d'Espoir, with a total of approximately 50 community members in attendance. The open house format was self-guided, allowing attendees to drop in at any time during the event to engage with project team members, who explained project details and answered questions. Large poster boards containing project information were displayed, and information fact sheets were provided as takeaways. Participants were also invited to contact Hydro via email with follow-up questions or information requests.

The majority of comments and questions on the project to date follow similar themes:

- *Benefits of employment and business activity.*

  There was positive feedback from local residents, workers, and business owners regarding the construction activity associated with the BDE Unit 8 project (along with other substantial future capital projects at the generating facility), who felt that the project would have a positive impact on local employment, business and economic activity during the construction phases. Hydro will work with the Towns and contractors to continue sharing information with local suppliers and businesses.

- *Perception that the additional unit will mean increased volumes of water outflow into the bay.*

  Questions were raised as to whether another unit would mean a greater volume of water coming through the plant, resulting in impacts on the marine environment and silt deposits in the bay. Hydro was largely able to alleviate these concerns through some education, providing an explanation that while the eighth unit provides additional capacity, the volumes of water used by the generating station throughout the course of a typical year will be largely unchanged as the size of the existing reservoir is not being modified.

- *Emergency response during construction.*

  Concerns were shared regarding the potential strain on the local medical clinic and emergency response personnel and resources, including the impact on community volunteer fire departments, as a result of the substantial increase in construction activity and the associated construction workforce. As a result, Hydro has committed to address this issue within its contractor engagement and orientation, by providing clear guidance and expectation that the contractors must plan to be "self-sufficient" in their emergency response plans.

- *Other comments and questions.*

  Other comments and questions raised include general inquiries about the overall project schedule, the current status and timelines for regulatory approval, and the potential location(s) of a worker camp during construction.

Open House Information Sessions on the BDE Unit 8 Project
St. Alban's and Milltown-Head of Bay d'Espoir

5.0 Ongoing Engagement

The feedback collected to date and going forward will be useful as Hydro develops its approach to the project and on continued information-sharing and discussion with communities and interested groups. For example, based on early engagement with Town Councils in the Bay d'Espoir area, Hydro will be putting plans in place during the BDE Unit 8 project execution to safely direct traffic to ensure that owners of cabins and other road users near the project site will continue to have access to those areas while construction activity is ongoing.

Hydro will continue information-sharing and engagement so that members of the public and interested groups are kept informed of progress, as these projects make their way through the regulatory process, provincial EA, and the execution phase, if approved. As discussions continue, Hydro will establish those approaches, engagement opportunities, and associated schedules in collaboration with the municipalities, Miawpukek First Nation, and other interested groups. A dedicated section of Hydro's corporate website containing information on BDE Unit 8 and other current and planned major projects, will be publicly available in the second quarter of 2025.

Schedule 4, Attachment 1

Basis of Estimate

Redacted

Schedule 4, Attachment 2

Basis of Schedule

newfoundland labrador hydro

Redacted

Schedule 5

Schedule 5

Avalon Combustion Turbine Project Evidence

Contents

Appendices

Attachments

1.0 Introduction

The Avalon Combustion Turbine ("Avalon CT") project is a critical component of Newfoundland and Labrador Hydro's ("Hydro") Minimum Investment Required Expansion Plan to ensure a reliable, cost-effective, and environmentally responsible electricity supply. A combustion turbine ("CT") has consistently been selected as a technically viable supply option, consistent with the lowest possible cost, throughout Hydro's *Reliability and Resource Adequacy Study Review ("RRA Study Review");* this has been further confirmed through the analysis presented in Schedule 3 of this application.

This project involves the addition of a 150 MW[1] CT generating unit at the Hydro-owned industrial site at the existing Holyrood Thermal Generating Station ("Holyrood TGS") location, as shown in Figure 1. This facility currently houses an existing thermal plant and CT plant supplying the Island Interconnected System. The location was selected as the addition of a generating resource on the Avalon Peninsula provides proximity to the main load center and is critical to facilitate the retirement of aging thermal assets, including the Holyrood TGS. This unit can be connected to existing transmission infrastructure and represents the lowest capital cost.

[1] All references to capacity are in nominal terms.

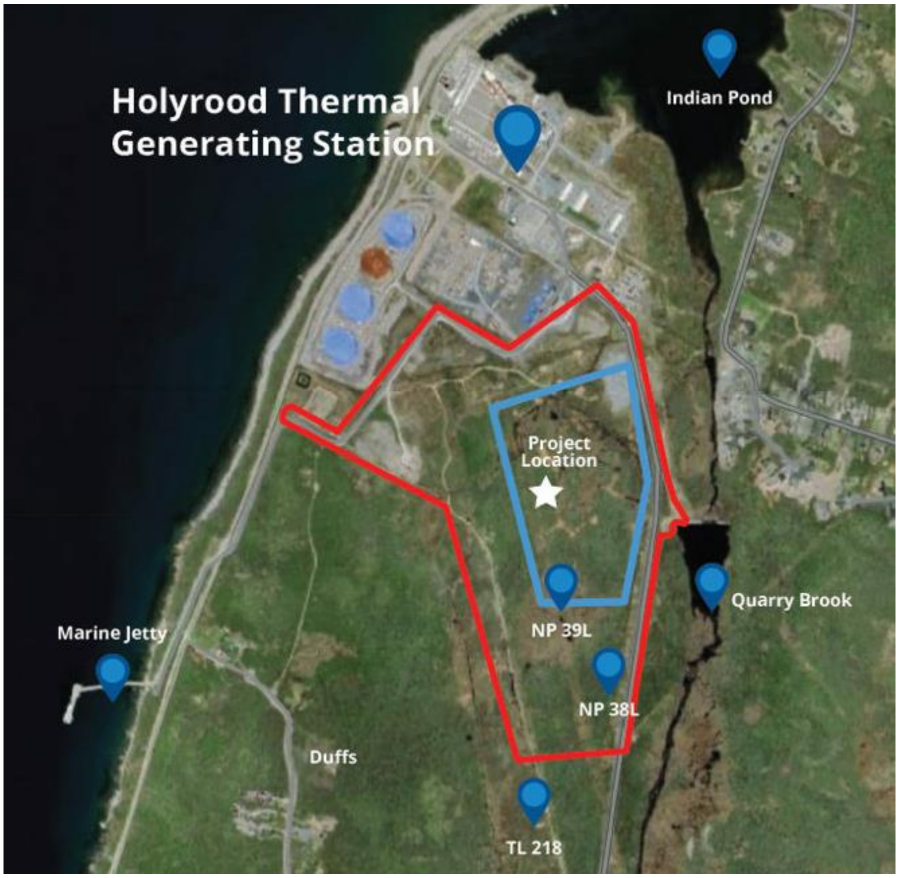

Figure 1: Site of Holyrood TGS and Future Avalon CT

Through front-end planning ("FEP") and front-end engineering and design ("FEED"), Hydro has developed a comprehensive project execution plan, including execution strategies in the areas of contracting, project management, project execution, project controls, health and safety, quality management and environmental management to support the project objectives and project delivery approach.

This schedule provides a description of the Avalon CT project and presents evidence in support of the 2025 Build Application, detailing the project scope, procurement approach, cost, schedule, stakeholder engagement, and risk management.

2.0 Project Scope, Requirements and Activities

2.1 Project Scope

The Avalon CT will supplement system capacity by adding a new multi-unit 150 MW generating facility, with supporting infrastructure and transmission interconnection that will provide peaking power support and standby generation in line with the 2024 Resource Adequacy Plan. From an emissions and diesel fuel perspective, the Best Available Control Technology ("BACT") will be specified and the plant will be designed so that it will be convertible for future integration of renewable fuels into the plant's operation as technology and supply evolves.

The project encompasses the construction of a new powerhouse to house the CT generating units, associated auxiliaries and essential mechanical and electrical systems, including control and protection equipment, fire protection, a demineralized water plant, a compressed air system, and black-start generators. To support operations, a new raw water intake and pumphouse will be developed to supply water for both domestic use and the demineralized water plant. Additionally, the fuel offloading system will include a new fuel tank farm, a truck offload delivery system for powerhouse supply, and a provision for a fuel line connection to the existing Holyrood Marine Terminal. Upgrades to the transmission and terminal station facilities incorporating station service transformer requirements involve establishing a new 230 kV high-voltage terminal station connected to generator step-up ("GSU") transformers, along with modifications and rerouting of existing transmission line TL218 and Newfoundland Power Inc. ("Newfoundland Power") transmission lines, ensuring seamless integration with the Island Interconnected System.

The Avalon CT project will include the engineering, procurement, construction, installation, commissioning, and testing of all works associated with the project, including:

- New No. 2 diesel tank farm and fuel delivery and transfer system;
- New raw water intake at Quarry Brook;
- New CT-generator(s) (totalling approximately 150 MW);
- New Avalon CT powerhouse complete with annexed control, water and black start buildings;
- New GSU transformers and isolated phase bus;

- New balance of plant auxiliary mechanical, electrical, protection and control, telecontrol, and telecommunications and communications equipment;
- New terminal station and transmission tie-in to existing Hydro transmission line TL218; and
- A provision for a pipeline to the existing marine jetty for future transfer of No. 2 diesel.[2]

2.2 Design Basis

The following subsections describe the technical and safety design requirements for key components.

2.2.1 Technical Design Requirements

Avalon Combustion Turbine Plant

The combustion turbine generators will be in a winterized building which will include the following features:

- CT packages including turbines, generators, lube oil system, starting system, and air intakes.
- Operation support and administration facilities:
  - Office and meeting room space;
  - Lunchroom, first-aid facilities, washrooms, and a locker room;
  - Warehousing space for materials handling, parts and tool storage;
  - Hazardous materials storage area; and
  - Workshop for minor operations and maintenance activities.
- Balance of plant auxiliary process and utility equipment including:
  - CT ancillary process and utility skids;
  - Electrical and battery rooms;
  - HVAC[3] system; and
  - Compressed air system.

[2] Hydro has included a provision for a pipeline in scope at a cost of less than 0.002% of total project budget; however, the final decision on execution of this scope is pending the outcome of the condition assessment on the current Holyrood TGS Marine Terminal and a decision to proceed with modifications to the Marine Terminal to allow delivery of diesel fuel.
[3] Heating, Ventilation, and Air Conditioning ("HVAC").

Turbine Units

- Multiple unit arrangement providing 150 MW of capacity at a power factor of 0.85;
- Turbines must have a fast start capability of 10 minutes;
- Failure of any equipment or system within a single unit shall not impact the operation or performance of the remaining units;
- BACT for emission control;
- Ability for fuel flexibility with options to transition to either renewable diesel, natural gas, or natural gas/hydrogen blend fuels, as these fuel sources become more readily available;
- Units will utilize hydraulic or electric start; and
- A single annular combustion system will be used for liquid fuel operation, which is expected to produce NOx[4] emissions of 38 ppm with the use of water injection technology.

Generators

- Power generation shall be achieved by multi-unit 13.8 kV generators;
- Each generating unit will be TEWAC;[5]
- Generators will have synchronous condensing capability;
- Each generating unit will be connected to an individual GSU transformer;
- All generators will operate at 3600 RPM;
- The system will require exciters, automatic voltage regulators, and synchronizing relays; and
- Isolated Phase Bus ducts will be used for connections between the generating units and the GSUs.

GSU Transformers

- Three GSU transformers (13.8 kV to 230 kV), with a fourth as a spare, located outside the powerhouse;

[4] Nitrogen Oxide ("NOx").
[5] Totally enclosed water air-cooled ("TEWAC").

- Transformers will be mounted on concrete pads with containment for oil leaks;
- Each transformer will include drainage to a common oil-water separator;
- Each unit will have a generator circuit breaker; and
- Transformers will be separated from each other by concrete firewalls.

Electrical Ancillary Equipment

- Each generating unit will be equipped with its own 13.8 kV switchgear containing the equipment necessary for interruption, grounding, and protection of the generator output;
- A station service power connection will be required to operate the auxiliary system within the generating station; and
- An emergency diesel generator connection and an essential panel will be provided to supply powerhouse essential loads, ensuring a black start capability, as needed.

Fuel Supply and Mechanical Ancillary Equipment

- Fire suppression system in the main building and combustion turbine enclosures;
- Water treatment plant for demineralized water production;
- Bulk fuel storage system consisting of two vertical tanks with a combined capacity of 10 days of fuel storage (approximately 4.8 million litres per tank);
- Associated fuel handling system consisting of fuel offloading apron, fuel pumphouse and piping system;
- Domestic water supplied by water treatment plant and domestic wastewater to septic tank and disposal field;
- Oil-water separator system for drains, fuel dyke de-watering and GSU transformer concrete containments;
- Main lube oil system for CT units;
- Overhead powerhouse crane; and

- Black start diesel generators (2 x 2 MW)[6] to support system start-up, as necessary.

Protection, Control and Monitoring

- CT controls will utilize vendor-supplied systems;
- Auxiliary systems to be controlled by programmable logic controllers;
- The plant will be controlled locally by an overarching Distributed Control System ("DCS"). Each unit will be equipped with a human-machine interface; and
- Standard Hydro protection relaying will be implemented.

Distributed Control System and Communications System

- A DCS will provide monitoring and control function to each unit and an all balance of plant equipment for the new plant;
- All critical alarms and data points shall be hardwired to the DCS and local operating station;
- The plant will include redundant instrumentation and control equipment consistent with good engineering design and Hydro standards;
- Standard Hydro networking equipment will be implemented (e.g., cisco switch, routers and firewalls, VoIP[7] phone system, and security camera systems); and
- The Newfoundland and Labrador System Operator will have remote control capability over the plant.

Terminal Station and Transmission Line Connection

- Concrete foundations and galvanized steel structures to support the terminal station electrical equipment and switchgear;
- The terminal station to interconnect plant to the 230 kV transmission line TL218 between the Holyrood Terminal Station and the Oxen Pond Terminal Station;

[6] Hydro will consider the use of existing black-start generators at the Holyrood site during detailed design.
[7] Voice over Internet Protocol ("VoIP").

- Reconfiguration of transmission line TL218 will require a new section of transmission towers and shield wire; and
- Relocation of Newfoundland Power transmission lines 38L and 39L.

2.2.2 Safety Design Requirements

The design of the project will prioritize both Safety in Design[8] and overall safety by minimizing hazards and mitigating failure modes that could pose risks to workers and the public throughout the construction, operation, and maintenance phases. Considerations and safety measures taken to ensure compliance with provincial Occupational Health and Safety regulations and enhance worker safety include:

- Compliance limits of approach requirements, ensuring that all equipment layouts maintain safe distances as mandated by applicable standards and codes.
- The design will incorporate robust systems for isolation and lockout, providing mechanisms to safeguard against hazardous materials, conditions, and energy sources.
- Arc flash risks will be addressed by constructing high-voltage equipment enclosures capable of containing or safely redirecting hazardous energy caused by electric faults.
- The use of hazardous materials will be minimized wherever possible, and in cases where elimination is impractical, protocols and infrastructure will ensure safe handling, transport, and disposal, reducing environmental and occupational risks.
- The design will aim to maintain noise levels at or below 85 decibels, mitigating the risk of hearing damage and ensuring compliance with noise exposure guidelines.
- To reduce the need for potentially hazardous tasks, such as confined space entry and work at heights, the design will minimize such requirements wherever feasible. For instances where these conditions cannot be avoided, the infrastructure will include fall arrest anchors, isolation points, and other features.

[8] Safety in Design refers to the act of putting hazard identification and risk assessment at the center of a project's design process.

This holistic approach to safety design reflects a commitment to protecting workers and the public by integrating proactive measures and regulatory compliance into every aspect of the project. It is Hydro's intention to involve operations and maintenance staff throughout the project lifecycle from a planning perspective to ensure their safety considerations are met through design, construction and turnover to operations.

2.3 Project Activities

This section provides a description of the expected project activities, including design, procurement, outage planning, construction, and commissioning.

2.3.1 Design Activities

In support of expansion plan development, Hydro engaged Hatch Ltd. ("Hatch") in 2023 to conduct a concept design study for Hydro to evaluate the feasibility of installing a CT as a source of fuel-fired backup generation on the Avalon.[9] The study 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. Based on-site assessments, Hatch determined Holyrood to be the recommended site. The assessments considered a range of factors including regulatory, environmental, technical and social criteria encompassing infrastructure accessibility and operational support. Hatch also recommended a plant capacity of 150 MW based on the current availability of fuel supply on the Island.

In 2024, Hatch Ltd. was re-engaged to advance the Avalon CT FEED, further developing the 2023 work and achieving a level of detail necessary to support the 2025 Build Application. This work included the following key activities:

- FEP: Development of the project Execution Plan and a contracting strategy;
- Development of Risk and Assumptions register to identify, document and manage project risks and assumptions;
- Facilitation of FEED-level constructability review to ensure feasibility and efficiency during construction;

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

- Preparation of an AACE[10] Class 3 cost estimate including a Basis of Estimate, provided as Attachment 1 to this schedule, and including a Quantitative Risk Analysis ("QRA")and associated Monte Carlo simulation,[11] to evaluate cost uncertainties;
- Preparation of an AACE Level 3 project schedule and Basis of Schedule, provided as Attachment 2 to this schedule, outlining a detailed timeline and critical path analysis for project execution; and
- Production of design and technical deliverables to a level of maturity to support an AACE Class 3 cost estimate. This included but was not limited to, design basis, design criteria, functional descriptions, CT technology comparison, BACT, process and instrument diagrams, calculations, specifications, single-line diagrams, data sheets, material take-offs, and general layout drawings.

Before initiating FEED, Hydro completed a geotechnical test pit program to determine the underlying soil conditions. The results were provided to Hatch for incorporation into the FEED design. An Environmental Assessment ("EA") will be completed by Hydro and the environmental registration will be submitted for approval in parallel with the 2025 Build Application.

This comprehensive scope of work established a robust foundation for project planning, budgeting, and risk management. The FEP activities for the project followed the Advanced Work Packaging ("AWP") approach established by the Construction Owners Association of Alberta and the Construction Industry Institute. This approach divides the project scope into logical packages. Firstly, the project area was divided into major project areas, and within each project area, there are one or more Construction Work Packages ("CWP") that define specific scopes of work. The established CWPs are outlined in Appendix A to this schedule. Each CWP then references relevant Engineering Work Packages ("EWPs") that define the engineering scope needed to support construction, such as drawings, procurement details, specifications, vendor information, etc. In the Execution Phase of the project, an Engineering, Procurement, and Construction Management ("EPCM") consultant will complete the detailed design and prepare the necessary EWPs.

[10] Association for the Advancement of Cost Engineering ("AACE").
[11] A probabilistic technique used to assess uncertainty and risk in cost projections.

2.3.2 Procurement Activities and Early Execution

During the Avalon CT FEP and FEED phase, a consultant was engaged to develop a contracting strategy, prepare a contract packaging plan, and identify procurement vendor packages.

Several major procurement items, including both the CT/Generator units and the GSU transformer packages, have been identified as being critical long-lead elements for the project due to their expected delivery time. Procurement of these critical components has been requested in Hydro's application for early execution capital work for Bay d'Espoir Unit 8 and Avalon Combustion Turbine ("Early Execution Application") currently before the Board of Commissioners of Public Utilities ("Board" or "Regulator"). This will mitigate risks associated with supply chain delays and market pressures to allow for project continuity through year-end 2025, while the Board and parties consider the 2025 Build Application.

As identified in the Early Execution Application, certain advance work and analysis are required to protect the necessary timelines for construction and protect project budget, this will mitigate the impact to ratepayers as a result of higher project costs associated with delays, and ensure project continuity through year-end 2025.

Hydro did not seek cost recovery for the expenditures proposed in the Early Execution Application. This was to allow for as expedient of a review process as possible, in the interests of regulatory efficiency and minimization of increases in costs to ratepayers that would result from a delayed project in-service date.

For the Avalon CT, these critical activities to accomplish early execution works include:

- Critical Path Request for Proposal ("RFP") preparation, issuance and award for CT and GSU transformers. This entails the detailed engineering and fabrication scheduling necessary to complete the work and includes firm confirmation of the final supply and install pricing and schedule.
- Complete EA Report and registration and continue with the stakeholder engagement process.
- Engage Engineering Support from an EPCM Contractor to support the following activities:
    - Complete geotechnical investigations and surveys needed to support the execution phase; and

    - Detailed execution planning activities, such as establishing project execution plans, contracting plans, and other planning documentation.

- Avalon CT interface optimization assessments in areas such as fire water supply, overall site fuel utilization, etc.
- Preparation of RFP and engage with contractors to complete initial geotechnical work and minor excavations in preparation to support line relocation and new line installations to ensure the overall schedule can be maintained.

Project estimates are time sensitive and supply chain pressures continue to increase; therefore, any delay during the regulatory proceeding schedule or during project execution increases risk of higher costs to ratepayers. Hydro’s Early Execution Application was made with these risks and implications in mind.

Failure to advance these critical activities as planned in 2025 would result in significant risk of project delays and increased costs. Additionally, the recently announced projects related to the December 2024 Memorandum of Understanding for the New Energy Partnership between Hydro and Hydro-Québec (“New Energy Partnership”), are expected to introduce market pressures on labour, engineering, equipment, and materials. Maintaining the planned schedule for the Avalon CT project will minimize overlaps with these new projects, reducing the risk of cost escalation and schedule impacts due to increased competition for resources.

Continuing with this planned work will ensure that the project team remains intact and fully engaged, which will improve continuity across the project phases and enable a seamless transition into the execution phase. This continuity is crucial to maintain project momentum, effectively manage risks and ensure alignment with strategic objectives.

In the execution phase, in addition to the early execution packages, additional procurement and construction contracts will be awarded for the primary civil package, powerhouse and balance of plant, tank farm, terminal station, transmission line interconnection and other scope elements.

The project’s procurement approach is discussed further in Section 2.6.

2.3.3 Outage Planning

Outage planning requires careful coordination and planning with contractors and Hydro Operations. Outages will be required to support the Avalon CT project during both the early execution and execution phases of the project to accommodate both the disconnection and reconnection of Newfoundland Power transmission lines and the final interconnection of the new Avalon CT facility into the Hydro electricity system prior to start up.

At a high level, major outages will be required for the following activities:

- Relocation of Newfoundland Power lines 38L and 39L;
- Re-routing TL218 into the new terminal station; and
- Tie-in to existing fire and waste water systems.

The duration and details will be finalized with Operations in accordance with required notification timelines and requirements. Any necessary outages will be carefully planned to minimize duration while ensuring the successful completion of work.

All other outages will be managed at the contractor level during installation and commissioning of systems.

2.3.4 Construction Activities

As previously noted, planning for the project followed the AWP approach. Using this approach, the project area was divided into logical portions of work. Within each project area are one or more CWPs. A CWP defines a specific scope of work such that it does not overlap with others. Project areas and CWPs represent the top levels of the Work Breakdown Structure for the project. The planned project areas and CWPs for the Avalon CT are summarized below and in Table 1 and Figure 2. More information on the CWPs within each project area is provided in Appendix A to this schedule.

Table 1: Project Area and CWP Summary

Project Area	Area number	CWPs in Area
Site Wide	0000	Four
Tank Farm	1000	Twelve
CT Plant	2000	Thirteen
Transformer Yard	3000	Seven
Switchyard	4000	Nine
Raw Water	5000	Ten
Fuel Offloading	6000	Ten
Transmission Line	7000	Six

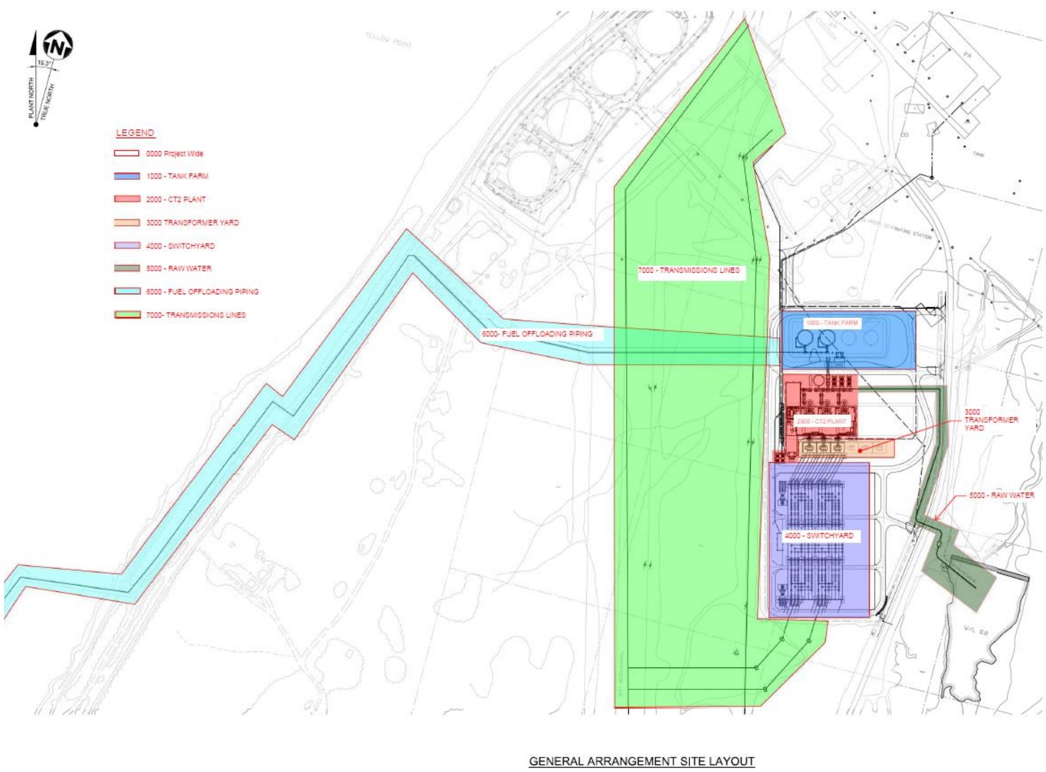

Figure 2: Project Areas

The construction activities can be further described through five general construction sequences, which are outlined below.

Sequence 1: Mobilization and Early Execution Works

- Coordinate re-routing of transmission lines 38L and 39L;
- Complete clearing work on site;
- Carry out minor earthworks and excavation required for line clearances;
- Bus 8 Station Service tie–in work; and
- Install pole line for construction power and lighting in the existing parking lot.

Sequence 2: Primary Civil Works Site Preparation

- Site clearing and levelling;
- Drainage configurations and systems;
- Earthworks and excavations, removal of grubbing or overburden;
- Raw water intake construction and pipeline interface;
- Piling and pad development;
- Access and internal roads;
- Grounding grid for terminal station;
- Fuel tanks dyke area liner; and
- Fencing and access gates.

Sequence 3: Powerhouse and Balance of Plant

- Building infrastructure foundation to cladding and roofing;
- Building services (e.g., fire and service water, HVAC, telecommunications, electrical, and sanitary);
- Powerhouse outfitting (e.g., combustion turbines, generators, motors, pumps, and auxiliaries);
- Outbuildings (e.g., black start generators, water storage, and fuel transfer pumphouse);

- Control Room, Electrical and Battery Room, and associated equipment and services;
- Outfit staff lunch room, change room, and miscellaneous building requirements; and
- Tank Farm installation (e.g., tanks, pipe rack, pipelines, and fire suppression system).

Sequence 4: High Voltage Terminal Station and Transmission Line Tie-in

- Construct terminal station structures and fencing;
- Outfit terminal stations with GSUs, primary breakers, terminal station building, stringing, and controls; and
- Construct TL218 transmission tie-in structures, shielding, and controls.

Sequence 5: Commissioning and Completions of Overall Facility

- Finishing of powerhouse (e.g., cleaning, painting, mechanical systems etc.);
- Final commissioning, including performance testing;
- As-built document completion, review, and acceptance; and
- Final acceptance, issue warranty certificates, and final certificate of completion.

2.4 Commissioning, Testing and Completion Activities

The commissioning, testing, and completion phases of Avalon CT will be managed by the EPCM contractor in alignment with Hydro's practices and processes. These phases represent critical and complex stages of project implementation, requiring coordinated efforts and collaboration from all stakeholders to ensure a successful outcome.

2.4.1 EPCM Contractor Responsibilities

The EPCM contractor will be responsible for the development of a comprehensive Commissioning Management Execution Plan that outlines the strategies for executing and managing commissioning activities, including:

- **Completions:** Ensuring all systems are ready for commissioning.
- **Commissioning Activities**: Systematic execution of commissioning processes.

- **Ready-for-Operation Verification:** Confirming operational readiness before handover.

2.4.2 Key Success Factors

The following elements are essential for effective commissioning execution:

- **Comprehensive Commissioning Plan:** Developed and agreed upon by all stakeholders.
- **Robust Safety Policy:** Adherence to a zero-harm principle for people, equipment and the environment.
- **Commissioning Schedule:** Sequenced according to the critical path, facilitating phased handover to Hydro operations of systems and areas based on ramp-up requirements.
- **Systematic Documentation Management:** Consistent and controlled documentation for commissioning activities.
- **Phased Testing Approach:** Ensuring the safety of equipment and quality of completion at each stage of pre-commissioning and commissioning testing in compliance with Hydro standards.
- **Experienced Commissioning Team:** Personnel with expertise in large-scale project commissioning.
- **Proactive Problem Management:** Early identification and resolution of potential issues or delays.
- **Integrated Commissioning Approach:** Involvement of project and operations teams to support an integrated commissioning and ramp-up effort.
- **Operational Readiness Process:** A complete readiness process to facilitate the achievement of turnover milestones in an orderly and controlled fashion. Readiness for Operations shall also have a structured process in place to verify the readiness of people, processes and systems required for turnover milestones.

2.4.3 Owner's Project Team Responsibilities

The Owner's[12] Project Team will oversee and support commissioning and completion activities performed by consultants and contractors, through the following surveillance and planning activities:

- **Verification of Mechanical Completion:** Ensure mechanical completion check sheets are complete.
- **Participation in Walkdowns:**[13] Ensure quality and readiness of installations.
- **Inspection and Testing:** Verify that all equipment is installed, adjusted, and functioning as part of the overall system to meet contract requirements.
- **Document Review:** Assess contractor quality documentation submissions where contractually applicable, such as inspection and test plans, functional and performance test plans, etc. for conformity with quality inspection and handover requirements.
- **Operation Validation:** Verify the satisfactory operation of the equipment, as specified.
- **Documentation Handover:** Ensure that all necessary documentation/information is turned over to operations.
- **Scheduling and Coordination:** Coordination with the commissioning team and Hydro in planning and scheduling testing activities.
- **Training and Familiarization:** Coordinate training sessions and equipment familiarization for operations personnel.
- **Tools and Spares:** Ensure delivery of required special tools and spares.
- **Operations Coordination:** Facilitate project and operations interface management (e.g., outages, etc.).
- **Oversight and Integrity Checks:** Provide owner oversight ensuring technical design integrity.
- **Interface Management:** Facilitate project access to required operations departments.

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[12] An Owner provides strategic oversight and has overall responsibility for success of a project. Hydro is the Owner for Avalon CT project.
[13] An on-site review, generally with contractor and/or other parties for the purposes of checking completion of work, to identify readiness for testing and/or handover, and to identify potential punch-list items.

- **System Access and Protection:** Coordinate the implementation, training and oversight of the Hydro Work Protection Code during system commissioning.
- **Handover Process:** Manage turnover of equipment to operations following commissioning acceptance of equipment, systems and/or part systems.
- **Updated Document Availability:** Ensure that all updated drawings, specifications, and operating and maintenance manuals are available for operation and maintenance of equipment.
- **Asset Management Delivery:** Organize asset management information delivery to operations.

2.5 Project Status

With reference to the Major Project phased approval process, which is illustrated in Figure 3, the project has reached the conclusion of the FEP Phase. The Avalon CT has concluded the FEP phase, which lays the foundation for the successful execution of major projects by ensuring sufficient work is undertaken to clearly define the need, project strategy, scope, cost, and schedule to enable well-informed decision-making early in the project lifecycle. At this stage, FEED and the associated AACE Class 3 cost estimate and Level 3 schedule have been completed. A decision support package outlining the project execution plan, budget, schedule, major risks and financing strategy has been presented and approved by Hydro leadership and the Board of Directors, enabling progress to the next phase contingent on approval by the Regulator.

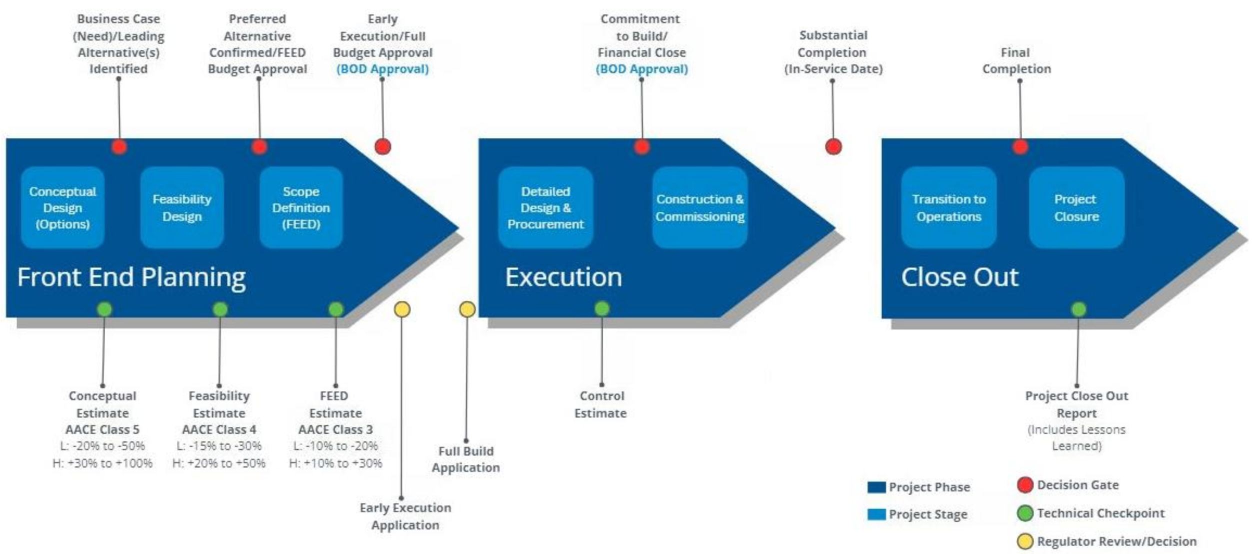

Figure 3: Major Projects Phased Approval Process

The current project status includes the completion of an internal sanction readiness review undertaken by Hydro's Internal Audit and Advisory Services department. The purpose of the review was to determine if an appropriate governance structure has been established and is effective for this project and if Hydro had completed appropriate planning work for the build application from a cost, schedule and risk perspective. This review focused on three primary objectives, and aligned with the Board's capital budget requirements where applicable, including:

1) **Maturity of Deliverables for Class 3 Estimate as per AACE[14] guidelines and Associated Schedule Risk:** Ensuring deliverables are at an appropriate stage as defined for an AACE Class 3 estimate. Deliverables are categorized into scope, capacity, requirements (e.g., regulatory requirements, safety, environment), strategy (e.g. contracting), planning (e.g. permitting, work breakdown structures, schedule, stakeholder plans), studies and technical deliverables (i.e. various designs). This objective also included assessing if both planning and schedule risks are identified and mitigated.

2) **Project Management Strategies:** Assessing the application of quantitative risk assessment methodologies, including Monte Carlo simulations, to ensure comprehensive risk management and alignment to AACE Recommended Practice 40R-08 Contingency Estimating. This review also included ensuring that FEED align with AACE Recommended Practice 34r-05, Basis of Estimate, which is used to define time, resources and money required for a project.

3) **Stewardship with a Focus on Governance:** Verifying the presence of governance structures to ensure effective oversight.

The review determined that the Avalon CT project documentation meets the requirements and expectations of the AACE guiding documents for the Class 3 estimate. The cost and schedule estimate is aligned with AACE requirement, including the Basis of Estimates and the quantitative risk assessment. An appropriate governance structure has been established and is operating effectively. Internal Audit and Advisory Services concluded that various recommendations and observations made throughout their review were incorporated into management's plans, as appropriate. No significant issues were

[14] AACE. (1997). *Cost Estimate Classification System – As Applied in Engineering, Procurement, and Construction for the Process Industries*, (AACE Recommended Practice RP 18R-97).

identified during this process, and there are currently no outstanding issues or recommendations that would impact the 2025 Build Application.

2.6 Procurement Approach

Hydro has developed its project approach to procurement for the Avalon CT in line with industry best practices and after thorough evaluation and consideration of project execution approaches. During the FEED phase, consultants were engaged to develop a project specific contracting strategy, including a recommended project delivery model, preparation of a contract packaging plan, and identifying procurement vendor packages. This contracting strategy is based on the outcomes of collaborative workshops to define project constraints, experiences and lessons learned from previous projects, and a general understanding of the advantages and disadvantages of various project delivery model types.

Project Delivery Model: EPCM Approach

The overarching project delivery model for this project is the EPCM approach. Under this model, the EPCM consultant will be responsible for:

- **Design Functions:** Detailed design of the project.
- **Procurement Functions:** Contract administration, expediting, logistics/transport, and material control.
- **Construction Management Functions:** Site project management, safety, engineering, construction monitoring, and project controls.

There are five major benefits for Hydro in taking this approach:

1) Allows Hydro to form a strong Owner’s team and leverage the expertise of the EPCM while retaining overall project control;

2) Empowers Hydro’s team to adopt a management and oversight mandate, ensuring effective control of the EPCM consultant’s performance;

3) Enables Hydro to focus efforts on owner-led core activities such as financing, procurement, environmental assessment, permitting, regulatory, and stakeholder engagement;

4) Utilizes proven systems and methods via the EPCM established systems, processes and procedures to drive efficiency and effectiveness; and

5) Provides the ability to allocate risks effectively through well-defined roles and responsibilities.

Contract Packaging Plan

The primary contract and long-lead procurement packages for the project are summarized in Table 2. While there will be additional contracts, sub-contracts, and procurement packages associated with the project, the major and long lead contracts are outlined in the table for clarity.

Table 2: Primary Contract and Procurement Package Summary

Contract /Procurement Package	Delivery/ Sourcing Methodology	Scope Notes
CT Supply	Hydro to specify and develop RFP during early execution. Delivery "Free Issue" to EPCM who will be assigned to management of the associated contract.	Design, manufacture, testing, delivery, and oversight of installation of CT Package. EPCM responsible for installation and integration in powerhouse.
GSU Transformer Supply	Hydro to specify and develop RFP. Delivery to EPCM for management of contract.	Design, manufacture, test, delivery, and oversight of installation of main GSU transformers. EPCM or subcontractor to install in terminal station.
EPCM Contractor	Hydro to specify and develop RFP package and manage contract.	EPCM services.
Primary Civil Package	EPCM to specify and develop bid package. EPCM to manage contract.	Primary construction contractor for the project responsible for civil works of all temporary and permanent site facilities.
Buildings and Balance of Plant	EPCM to specify and develop bid package. EPCM to manage contract.	Installation of building and balance of plant equipment including interface with existing site systems as necessary.
Fuel Storage and Handling	EPCM to specify and develop bid package. EPCM to manage contract.	Installation of piping, tanks, pumphouse building and associated equipment.
Terminal Station and Transmission Line Tie-in	EPCM to specify and develop bid package. EPCM to manage contract.	Construction including foundations and equipment stringing.
Early Execution Works (Transmission Line Relocation; initial site preparation and Avalon CT Optimization)	Hydro to specify and develop package, procure necessary materials, and manage contract with Newfoundland Power and early execution minor civil works.	Relocation/Construction including structure foundations, towers, hardware, and stringing. Minor civil works.

The proposed contract packaging plan is designed to minimize interface issues that could result in legal claims regarding delays or interfaces with other contracts and/or the owner, as a result of one scope of work impeding the completion of another. It also puts a focuses on accountability so that responsibilities are clearly defined. There are also inherent efficiencies related to securing construction labour and resources, and setup and maintenance of site services.

3.0 Project Cost and Assumptions

The cost estimating structure for this project is designed to ensure financial robustness and risk preparedness.

The project capital cost estimate includes the following:

- Base Cost, which includes prices for direct costs, such as equipment, materials, etc., and indirect costs, such as engineering;
- Design Allowance, to account for natural changes and refinement of scope of work as engineering progresses; and
- Contingency, to account for uncertainties outside of the Hydro’s control – they are the “known unknowns” that are within the project scope (e.g., geotechnical conditions).

The sum of these costs make up the project capital cost estimate. To establish the planned project budget, the following is also included:

- Interest during construction (“IDC”), to account for the cost of borrowing during project construction; and
- Escalation, which accounts for anticipated increases in labour costs and material prices over the course of construction of a multi-year project.

The Authorized Budget, set at P85[15] confidence level in keeping with the Muskrat Falls inquiry recommendation, encompasses the planned project budget and Management Reserve.[16] This probabilistic estimating approach ensures proper risk assessment during budgeting exercises. The use of a P85 estimate is consistent with Justice LeBlanc's recommendations in the final report on the Muskrat Falls Inquiry[17] and is further supported by the complexity assessment ranking of the project.

The following sections provide a detailed breakdown of each cost component.

The cost estimate was primarily developed by Hatch, with further estimating work being performed by Hydro. Further detail on estimate development is provided in Attachment 1 to this schedule.

3.1 Quantitative Risk Analysis

A QRA is a "Risk analysis used to estimate a numerical value (usually probabilistic) on risk outcomes wherein risk probabilities of occurrence and impact values are used directly."[18] For the Avalon CT project, a QRA was facilitated by the FEED Consultant (Hatch) with participation by Hydro, as well as members of the FEED consultant design and project team.

These QRA sessions collected data for the FEED consultants' cost, schedule and risk expert to model the project using an industry standard statistical modelling tool—a Monte Carlo simulation. This Monte Carlo simulation is done for a variety of items across the entire estimate, at the same time. The outcomes of all of these calculations and analyses provides a statistical probability curve of outcomes for the overall project, informing the management team on recommended values for contingency and Management Reserve. Hatch performed its QRA using the parametric method, which uses a qualitative ranking of specific execution categories and elements that research has shown as providing a more accurate indication of the likelihood of success. The qualitative rankings are input to the Monte Carlo

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[15] A probabilistic cost estimate in which there is an 85% probability that the actual cost will be less than or equal to the budget.
[16] Management Reserve is an industry-standard tool that is used to manage risk and to address issues that may arise that are outside of the control of Hydro. It serves as additional funds in a project budget that are set aside for strategic risks and potential external, uncontrollable factors that may arise throughout the course of the project. It is not intended to be used to accommodate foreseeable changes in scope, schedule, and cost that are within Hydro's control. Considered "unknown unknowns" that are within the project scope (e.g., government policy changes). Management Reserve is discussed further in Section 3.2.6.
[17] "Muskrat Falls: A Misguided Project, Commission of Inquiry Respecting the Muskrat Falls Project," The Honourable Richard D. LeBlanc, Commissioner, March 5, 2020, vol. I, Key Recommendation 5, pp. 61–62.
[18] AACE. (2024). *Cost Engineering Terminology* (AACE Recommended Practice RP 10S-90, p. 104).

simulation to generate an overall probabilistic curve. Picking a point on this curve provides the probabilistic outcome at that point, also called the P-value (e.g., P50 equates to 50% probability that project will be less than or equal to on the project budget).

3.2 Estimated Amount

The expected cost estimate is based on preliminary design, conforms to AACE Class 3 cost estimate requirements, and is deemed to have an accuracy range of -23% to +26%.[19]

The Authorized Budget for the Avalon CT of $891 million includes life-to-date costs as well as estimated direct construction costs, indirect construction costs, contingency, escalation, IDC, and Management Reserve. Appendix B to this schedule, provides a breakdown of the project budget. Further discussion of the underlying assumptions and individual cost estimate components are provided in the following sections.

3.2.1 Assumptions

Assumptions underpinning project execution and estimating are contained in Attachment 1 and 2, the Basis of Estimate and Schedule, respectively, to this schedule. Some of the key assumptions include:

- An adequate labour supply is available;
- Site geotechnical conditions are not materially different from that expected;
- No abnormal (i.e. outside of normal observed statistical history) weather events occur during construction;
- There will be no labour disruptions during execution of the work; and
- Regulatory approvals, including Early Execution will be generally granted as assumed in the project schedule.

[19] Please refer to page 48 of Attachment 1, Basis of Estimate.

3.2.2 Base Cost– Direct Construction Costs

The Base Cost was primarily developed by Hatch. The estimate was constructed using subject matter expert knowledge, FEED quotations and data collected in Hatch's estimating database from other, similar projects.

The Base Cost was developed by dividing the work scope into facilities and areas, identified by a Facility Breakdown Structure as shown in Table 3. These were further subdivided into CWP for detailed assessment, as shown in Table 4. The cost estimation for each CWP within a facility was estimated at a detailed level, based upon quantities and FEP consultant (Hatch) historical pricing, estimating database norms and allowances for work execution. The Avalon CT project was divided into the following facilities and CWPs for estimating and planning purposes:

Table 3: Summary Facility Coding

Facility Code	Description
1000	Site Preparation and Improvements
2000	Building, Structures and Foundations
3000	Power Generation and Auxiliaries
4000	Fuel Storage and Handling
5000	Electrical Power Systems
6000	Instrumentation and Control
7000	Common Services Equipment and Systems
8000	Construction Indirects
9000	Owner's Costs[20]

Table 4: Summary Construction Work Packages

Construction Work Package	Description
0000	Site Wide
1000	Tank Farm
2000	Combustion Turbine Plant
3000	Transformer Yard
4000	Switchyard
5000	Raw Water
6000	Fuel Offloading
7000	Transmission Lines

[20] Owner's costs included in the FEED consultant's estimate for inclusion in the FEED QRA.

The unit rate costs and labour estimates are based upon other comparable projects, and include worker productivity assessments. The Base Cost Estimate includes detailed cost proposals and estimates for all project phases, including estimates for:

- Design;
- Procurement;
- Fabrication;
- Manufacturing;
- Transport;
- Civil construction works;
- Equipment installation; and
- Testing and commissioning.

It also accounts for contractor indirect costs, such as site services and temporary facilities.

The estimate includes information that came from a variety of sources. Equipment, such as the CT pricing, was obtained from budgetary vendor quotations. Pricing for other minor equipment was informed by recent historical data from other projects.

3.2.3 Base Cost – Indirect Construction Costs

Indirect construction costs[21] were estimated by Hatch through a detailed buildup of the required equipment, facilities and support personnel based on subject matter expertise, plus allowances as deemed necessary.

Some indirect items that are included in the estimate are:

- Mobilization and demobilization;

[21] Indirect costs are defined as costs not directly attributable to the completion of an activity, which are typically allocated or spread across all activities on a predetermined basis. In construction, (field) indirects are costs which do not become part of the installation, but which are required for the orderly completion of the installation, and may include, but are not limited to, field administration, direct supervision, capital tools, start-up costs, contractor's fees, insurance, taxes, etc.
AACE. (2024). *Cost Engineering Terminology* (AACE Recommended Practice RP 10S-90, p. 66).

- Freight;
- Site services, such as snow clearing, waste management, and materials handling;
- Management and support staff;
- Legal and insurance services;
- Temporary facilities, including setup, operation and maintenance; and
- Site access, such as roads, walkways and staircases.

3.2.4 Project Contingency

Contingency was estimated as part of a QRA conducted as part of the FEED project stage. This QRA was a joint effort between the FEED Consultant (Hatch) and Hydro. Further information is provided in Attachment 1 to this schedule.

3.2.5 Indirect Costs, Escalation and Interest During Construction

Hydro's Indirect Costs

Hydro's indirect costs include the costs for the Hydro Owner's team, as well as for an EPCM consultant. The cost estimate includes labour costs as well as additional elements such as travel to the Holyrood area, Hydro support during construction and commissioning, as well as various corporate costs, such as insurance. The estimate for the EPCM consultant was estimated by Hatch, based on benchmarking of similar projects.

Economic Related Costs – Escalation

Since the onset of the COVID-19 pandemic, escalation has been difficult to account for given the global turmoil and supply chain disruptions. There are a variety of methods that can be used to estimate escalation factors, but the primary commonality is an attempt to predict future economic and market conditions. This projection becomes increasingly difficult over longer-term periods. Hydro has developed a standardized approach to escalation projections, which is utilized on all of its projects, including Avalon CT. The project management reserve does provide a mechanism to deal with a certain level of unknown market volatility that may be encountered throughout the life of the project. Further information on some of the key risks that were considered as part of the QRA can be found in Table 6 in Section 6.0.

Hydro also has a standard method of calculating IDC, which is applied to capital expenditures, including this cost estimate. Further information on Hydro's assumptions are provided in Attachment 1 to this schedule.

3.2.6 Management Reserve

Management Reserve is an amount that is held outside of the performance measurement baseline for management control purposes that is reserved for unforeseen risks that is within the project scope (i.e., "unknown unknowns").[22] The Management Reserve equips Hydro to respond to strategic risks or unforeseen events quickly. Projects can continue to progress and remain on schedule despite obstacles outside of Hydro's control. It is industry standard to include management reserve in project estimates especially for large complex projects, and was a key finding within the Muskrat Falls Inquiry. Commissioner LeBlanc noted that *"A reasonable reserve for strategic risk should have been included in the Project's cost estimate and made known to [the Government of Newfoundland and Labrador]."*[23] A well-managed Management Reserve is a crucial tool that increases the likelihood that the project will succeed.

During the strategic risk process a number of strategic level risks which are generally outside of the projects teams' sphere of influence were considered and modelled statistically during the cost estimate process. These include risk such as:

- Extension of the approval process;
- Availability, retention and productivity of construction labour; and
- Procurement, Fabrication, Manufacturing and Supply/Transport from a market supply perspective.

The Muskrat Falls Inquiry recommended that for large projects a range of cost estimates should be generated and that funding should be based on a probability of not less than 85%. The Management Reserve for the Avalon CT project was calculated by determining the budget at the 85% confidence level

[22] PMBOK Guide, p. 242.
[23] "Muskrat Falls: A Misguided Project, Commission of Inquiry Respecting the Muskrat Falls Project," The Honourable Richard D. LeBlanc, Commissioner, March 5, 2020, vol. I Key Finding 41, p. 53.

(based on the Monte Carlo simulation conducted as part of the QRA) and subtracting the Base Cost. Further details are contained in Attachment 1 to this schedule.

Management Reserve is included within the Authorized Budget but remains outside of the project team's authorization to spend. The use of Management Reserve funds requires the approval of Hydro's Chief Executive Officer.

4.0 Project Schedule

A detailed execution schedule, supported by a schedule basis, was developed during FEED by Hatch. This schedule has been further developed and integrated with Hydro scopes, to form the overarching Project Control Schedule, provided within Attachment 2 to this schedule.

The anticipated in-service date for the Avalon CT is late 2029. This is based on several assumptions, detailed below, including the timing of delivery of long–lead equipment.

The project critical path is driven by the design and modelling of the CT and GSU transformers, the contract award for these units, the provision of design information necessary to complete other design and procurement items, and the manufacturing and delivery of the units. This delivery timeline dictates overarching timeline for the project execution, and is shown in Appendix C to this schedule.

4.1.1 Project Major Milestones

Table 5 provides the anticipated timelines for major milestones necessary to meet the schedule best positioned to achieve the cost and in-service timeline. Deviations from this schedule will increase cost and extend in-service accordingly.

Table 5: Project Major Milestones

Milestone Description	Date
EA Release	Q2 2025
Award Transformer Contract	Q2 2025
Award CT Contract	Q3 2025
Award EPCM Contract	Q3 2025
Build Application Approval	Q4 2025
Start Main On-Site Construction Works	2026
Start of Commissioning	2029
Turbine Ready for Commercial Operation	2029

As outlined in Schedule 1, Hydro is working to advance the Avalon CT as fast as possible to reduce the reliance on aging thermal assets, and reduce costs associated with maintaining and operating these assets. As a result, Hydro has advanced the in-service date of the CT within the 2025 Build Application to late 2029. As outlined in the 2024 Resource Adequacy Plan, advancing the in-service date for the Avalon CT also continues to have a material benefit to the reliability of the Island Interconnected System in the event of a prolonged Labrador-Island Link bipole outage.

4.1.2 Scheduling Constraints and Considerations

The planned work the Avalon CT Project is subject to several constraints including approvals, equipment lead times, and electrical grid interactions.

Approvals

There are a number of risks that could impact the execution schedule. The project schedule assumes time for a thorough review and evaluation of the project through a regulatory proceeding necessary to obtain Board approval by the end of the fourth quarter of 2025. Hydro requested Board approval of the Early Execution Application, including procurement of critical path equipment such as the CT and GSU transformers, to enable project continuity while allowing for the time necessary for the overall regulatory proceeding. Delays in receiving regulatory approval for the 2025 Build Application beyond the end of 2025 would have implications for the schedule and increases the risk of a full year delay if Hydro cannot commence the planned seasonal construction activities as scheduled. It is projected that there will be multiple, concurrent projects with similar timelines, both within and outside of Hydro. Analysis indicates that a one-year delay in project initiation could result in a cost impact of $30 million to $50 million.

The EA release is not anticipated to be a schedule constraint, given that this is an existing brownfield site, and the EA process is planned to be completed within the 2025 Build Application review timeframe.

Equipment Lead Times

The project schedule is largely driven by the lead time for the CT unit and GSU transformer, which sets the overarching timeline for the project execution. The timeline for this major component is based upon budgetary quotation information. It is critical to proceed with initial vendor engagement concurrent with Board review to ensure the project remains on schedule as presented in Appendix C to this schedule, as these specialized vendors commit to schedule manufacturing of components as they accept orders.

Electrical Grid Interactions

The project includes electrical inter-connections with existing transmission lines, requiring the addition of new transmission infrastructure. This work must be coordinated with specific planned transmission outages.

Certain portions of the commissioning work for the Avalon CT requires interaction with the grid. To avoid any inadvertent impacts to the grid stability or customer supply, this commissioning is scheduled to occur outside of the winter period. In the current project schedule, the online commissioning activity is being planned to avoid grid interactions during sensitive periods.

5.0 Consultation and Public Engagement

Hydro has implemented a proactive stakeholder engagement strategy for the Avalon CT Project, focusing on early communication, public input opportunities, and sustained collaboration throughout the project's planning, approvals, and execution phases. The primary interested groups identified for this project include municipal governments (Town of Holyrood, and Town of Conception Bay South), residents of Holyrood, Conception Bay South, Seal Cove, and regional business organizations (econext, and Conception Bay Area Chamber of Commerce), Newfoundland Power, and government entities (House of Assembly representatives, provincial and federal regulatory bodies). Hydro is committed to ongoing engagement and keeping employees, the public, and other interested groups informed of progress as work moves forward. A summary of Hydro's engagement activity is provided in Appendix D to this schedule.

6.0 Risks and Risk Management

Effective risk management is critical to the success of any project. It allows Hydro to proactively identify risks that could affect the project objectives, which, in turn, increases the predictability of project outcomes, helps manage complexity, helps maintain project cost, schedule, and budget, supports change management, and generally supports the delivery of the intended strategic business objectives associated with the project. For more information on how Hydro manages risk for major projects please refer to the Major Projects Governance Framework, provided as Attachment 1 to Schedule 1 of this application.

During the FEED phase of the Avalon CT project, a comprehensive Risk Register has been developed. This document captures all identified risks, their analysis, and corresponding mitigation plans. The ongoing monitoring and refinement of this register will be critical to maintaining alignment with project goals and responding to evolving risks. By embedding risk management into all phases of the project, Hydro ensures a proactive approach toward addressing uncertainties and protecting project success.

Hydro are closely monitoring several evolving risks that have been identified in the risk management process. These include: the potential impact of tariffs on material and equipment costs and foreign currency exchange rates; and the potential impacts of competing projects including the recently announced planned work related to the New Energy Partnership, which will introduce market pressures on labour, engineering, equipment, and materials. Hydro will continue to monitor these emerging risks and forecast the potential impacts throughout project execution.

Project risks have been considered in the establishment of the project budget. The identification and quantification of risk was undertaken by subject matter experts, and a QRA using a Monte Carlo simulation was employed to develop contingency and Management Reserve values which account for the risks identified. This is a prevalent methodology in project management and other disciplines for risk analysis, and decision-making.

Table 6 provides a summary of the most significant project risks identified to date.

Table 6: Summary of Top Project Risks

Risk Title	Risk Description	Mitigation Notes
Supply chain pressures may increase the cost of goods and increase delivery times.	Global supply chain delays caused by global energy demand increases, green projects, etc. may impact schedule and cost. The recently announced planned work related to the New Energy Partnership will introduce market pressures on labour, engineering, equipment, and materials.	• Maintain the planned project schedule. • Early procurement of long lead or critical items. • Pursue early engagement and secure manufacturing slots in advance of contract award. • Consider appropriate Management Reserve for strategic risks.
Trade disputes with the United States of America results in tariffs that cause increases in costs.	Tariffs may lead to both price increases and negative foreign currency exchange rate changes.	• Established baseline foreign currency and escalation rates, according to corporate assumptions. • Engagement with critical suppliers in early execution phase to understand potential tariff impacts on budget. • Consider utilization of Management Reserve to address cost variances induced from global trade disputes.
CT Supplier Backlog.	As a result of competition from other projects there may be limited supplier resources, added complexities in international supply chain, and a potential “sellers market” resulting in higher costs and extended delivery schedule. This may also create a challenges in obtaining Long-Term Service Agreement commitments.	• Enhanced oversight during design and manufacturing process. • Engage with suppliers to explore contracting models and risk allocation strategies. • Execute procurement in Early Execution phase.
Resource availability for Owner and EPCM team.	As a result of competition from other major projects, there may be limited availability of resources and/or contractors to compete for planned scopes. This could impact ability to complete deliverables as per required milestones and resulting in both cost and schedule impacts.	• Finalized decision on contracting strategy (EPCM). • Engaged several qualified contractors, demonstrate that project is required and Hydro is actively advancing regulatory processes for approval.
Regulatory (Board) approval process extends beyond the assumed timeline.	If the regulatory approval process extends beyond the assumed timeline, the project schedule will be delayed and the ability to make contract commitments to support project schedule will be impacted. This will have both a schedule and cost impact due to cost escalation and loss of project momentum.	• Produce a robust Board application and work closely with Board during the application process. • Receive timely Board approval of Early Execution Application.

Risk Title	Risk Description	Mitigation Notes
Internal decision-making process and time required.	If internal decision-making processes are not efficient, it can lead to project execution delays and schedule and cost impacts. For example, time sensitive decisions such as awarding of contracts (equipment and construction), or proceeding with early execution. Cost impact of a one-year delay is estimated at $30 million to $50 million.	• Established Project Governance structure, project steering committee, and project leadership team with clear limits of authority. • Established processes and systems to facilitate effective decision making including a review of authority levels. • Developing contingency plans for key personnel so decisions can be made when there are competing priorities or absences. • Corporate Interface Manager in place to manage all interfaces between Major Projects and Corporate Groups.
Failure to complete early execution.	Early execution will provide risk mitigation by maintaining the overall project schedule and budget that were established during FEED. If planned early execution is not advanced as planned, the overall project will be delayed and project costs will increase.	• Sought approval to proceed with required early execution to maintain current project schedule.

7.0 Conclusion

The Avalon CT is a critical component of Hydro's plan to ensure future supply adequacy for the Island Interconnected System. It will allow for the retirement of aging thermal assets, support system reliability and have supply in place to meet load growth. Hydro is recommending the addition of a new 150 MW CT plant at the Holyrood TGS, as the Avalon CT was consistently selected as one of the preferred, least-cost, environmentally responsible resource options, and is a significant first step in meeting the electricity demands of both the Minimum Investment Required and Reference Case scenarios.

The project is recommended to proceed under an EPCM delivery model to balance Hydro's oversight with external expertise. This approach helps to ensure effective risk management, coordination, and the successful delivery of all phases, from design to commissioning. The current project schedule assumes project completion in late 2029. To allow for a fulsome review of this application while maintaining the project schedule, Hydro has filed an Early Execution Application to continue the advancement of procurement of critical components, including the CT and GSU Transformer, which will mitigate risks associated with supply chain delays and market pressures.

The planning, construction, and integration of new generating resources will take years, underscoring the need for expedient action. Project estimates are time sensitive and supply chain pressures continue to increase; therefore, any delay during the regulatory proceeding schedule or during project execution increases risk of higher costs to ratepayers.

The Authorized Budget of approximately $891 million for the project, set at a P85 confidence level, ensures an 85% probability of staying within budget, balancing cost efficiency with prudent risk management, consistent with Justice LeBlanc's recommendations in the final report on the Muskrat Falls Inquiry. Hydro has assembled an experienced Major Projects department that has the necessary expertise to execute these large-scale projects. Hydro is confident in its ability to deliver the Avalon CT, utilizing lessons learned from previous experiences, recommendations from the Muskrat Falls Inquiry, and a robust risk management strategy to mitigate risks to project cost and schedule.

Appendix A

Construction Work Packages

Avalon Combustion Turbine

Construction Work Packages

Careful planning and packaging of construction by geographic area and discipline will ensure that the required engineering deliverables, materials, and construction resources support the path of construction and schedule.

The CWP Program is defined and built in collaboration with Engineering and Procurement using the agreed sequence of construction to develop the CWP list and associate the engineering work packages and procurement packages through engineering deliverables. The CWP will be the common thread for schedule development, estimate development, and the basis for controlling site activities and progress reporting.

The CWP defines a measurable and controllable segment of work within the construction scope and is the basis for developing installation work packages by contractors.

Typically, a CWP includes:

- Scope of work, technical deliverables, vendor documents, bill of materials, installation specifications and reference documents;
- Budget;
- Schedule; and
- Safety, environmental and quality requirements.

Table 1 provides the breakdown of CWPs for the Avalon CT project by area.

Table 1: CWP by Project Area

Project Area (Area Number)	CWP	
Site Wide (0000)	CWP-0000-A-1-001 Site Development	CWP-0000-D-1-001 Site Wide Roadworks
	CWP-0000-A-1-002 Site Wide Roads, Drainage, Final Grading	CWP-0000-P-1-001 Site Wide Piping
Tank Farm (1000)	CWP-1000-A-1-002 Tank Farm Roads, Drainage, Final Grading	CWP-1000-N-1-001 Tank Farm Tanks
	CWP-1000-C-1-001 Tank Farm Concrete	CWP-1000-P-1-001 Tank Farm Piping
	CWP-1000-E-1-001 Tank Farm Earthworks	CWP-1000-L-1-001 Tank Farm Electrical Equipment
	CWP-1000-F-1-001 Tank Farm Architectural	CWP-1000-J-1-001 Tank Farm Control & Instrumentation
	CWP-1000-S-1-001 Tank Farm Structural Steel	CWP-1000-R-1-001 Tank Farm Cable Tray & Conduit
	CWP-1000-M-1-001 Tank Farm Mechanical Equipment	CWP-1000-W-1-001 Tank Farm Wire and Cables
CT Plant (2000)	CWP-2000-A-1-001 CT Plant Site Development	CWP-2000-P-1-001 CT Plant Piping
	CWP-2000-E-1-001 CT Plant Earthworks	CWP-2000-L-1-001 CT Plant Electrical Equipment
	CWP-2000-C-1-001 CT Plant Concrete	CWP-2000-J-1-001 CT Plant Control & Instrumentation
	CWP-2000-F-1-001 CT Plant Architectural	CWP-2000-Q-1-001 CT Plant Insulation
	CWP-2000-S-1-001 CT Plant Structural Steel	CWP-2000-R-1-001 CT Plant Cable Tray & Conduit
	CWP-2000-M-1-001 CT Plant Mechanical Equipment	CWP-2000-W-1-001 CT Plant Wire and Cables
	CWP-2000-N-1-001 CT Plant Tanks	
Transformer Yard (3000)	CWP-3000-E-1-001 Transformer Yard Earthworks	CWP-3000-R-1-001 Transformer Yard Cable Tray & Conduit
	CWP-3000-C-1-001 Transformer Yard Concrete	CWP-3000-S-1-001 Transformer Yard Structural Steel
	CWP-3000-L-1-001 Transformer Yard Electrical Equipment	CWP-3000-W-1-001 Transformer Yard Wire and Cables
	CWP-3000-J-1-001 Transformer Yard Control & Instrumentation	
Switchyard (4000)	CWP-4000-A-1-001 Switchyard Site Development	CWP-4000-L-1-001 Switchyard Electrical Equipment
	CWP-4000-E-1-001 Switchyard Earthworks	CWP-4000-J-1-001 Switchyard Control & Instrumentation
	CWP-4000-C-1-001 Switchyard Concrete	CWP-4000-R-1-001 Switchyard Cable Tray & Conduit
	CWP-4000-F-1-001 Switchyard Architectural	CWP-4000-W-1-001 Switchyard Wire and Cables
	CWP-4000-S-1-001 Switchyard Structural Steel	
Raw Water (5000)	CWP-5000-E-1-001 Raw Water Earthworks	CWP-5000-P-1-001 Raw Water Piping
	CWP-5000-C-1-001 Raw Water Concrete	CWP-5000-L-1-001 Raw Water Electrical Equipment
	CWP-5000-S-1-001 Raw Water Structural Steel	CWP-5000-J-1-001 Raw Water Control & Instrumentation
	CWP-5000-M-1-001 Raw Water Mechanical Equipment	CWP-5000-R-1-001 Raw Water Cable Tray & Conduit
	CWP-5000-N-1-001 Raw Water Tanks	CWP-5000-W-1-001 Raw Water Wire and Cables

Project Area (Area Number)	CWP	
Fuel Offloading (6000)	CWP-6000-A-1-001 Fuel Offloading Site Development	CWP-6000-P-1-001 Fuel Offloading Piping
	CWP-6000-E-1-001 Fuel Offloading Earthworks	CWP-6000-L-1-001 Fuel Offloading Electrical Equipment
	CWP-6000-C-1-001 Fuel Offloading Concrete	CWP-6000-J-1-001 Fuel Offloading Control & Instrumentation
	CWP-6000-S-1-001 Fuel Offloading Structural Steel	CWP-6000-R-1-001 Fuel Offloading Cable Tray & Conduit
	CWP-6000-M-1-001 Fuel Offloading Mechanical Equipment	CWP-6000-W-1-001 Fuel Offloading Wire and Cables
Transmission Line (7000)	CWP-7000-A-1-001 Transmission Lines Site Development	CWP-7000-J-1-001 Transmission Lines Control & Instrumentation
	CWP-7000-E-1-001 Transmission Lines Earthworks	CWP-7000-W-1-001 Transmission Lines Wire and Cables
	CWP-7000-S-1-001 Transmission Lines Towers	
	CWP-7000-L-1-001 Transmission Lines Electrical Equipment	

Appendix B

Project Budget Breakdown

Avalon Combustion Turbine

newfoundland labrador hydro

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Appendix C

Critical Path Schedule

Redacted

Appendix D

Avalon Combustion Turbine Engagement Summary

newfoundland labrador hydro

1.0 Introduction

For both the proposed projects in the 2025 Build Application, Hydro established objectives for engagement and information-sharing, including keeping local municipal governments, community residents and businesses, and other interested groups informed; providing public information and feedback opportunities; and establishing a channel for ongoing communication and collaboration as projects continue through planning, approvals, and execution. This engagement was initiated with primary interest groups early in the project planning phases, and well in advance of the regulatory approval process and EA registrations.

2.0 Building on Reliability and Resource Adequacy Insights

This project-specific engagement builds on the previous digital engagement of customers conducted as part of the *RRA Study Review*, which provided useful insights early in the process. In particular, input gathered from the 2024 digital engagement highlighted that customers in this province place the highest value on affordability first, then ensuring continued reliability when making decisions on what new electricity projects to pursue and invest in. Further, they prioritize lower electricity costs before investment in increased reliability or renewable technologies. In fact, the digital engagement results found that the source of electricity is a relatively lower priority for customers when compared to cost and reliability.

3.0 Early Engagement of Interested Groups

Engagement on the 2025 Build Application projects began early in the planning stages. Hydro gathered feedback and insights from communities and other interested groups primarily through:

1) Meetings and briefings with key groups with interest in the respective projects;

2) Community "open house" information sessions held in the proposed project locations, aimed at informing local residents and inviting their feedback; and

3) Public comments and questions were also accepted via email.

Hydro has been sharing information with the public and other interested groups, engaging and meeting face-to-face in the communities in which it operates. From the early project planning phases, Hydro has met with Town Councils and senior staff in Holyrood and Conception Bay South. Hydro also met directly with Members of the House of Assembly for the area: Helen Conway-Ottenheimer, Member for the District of Harbour Main; and Barry Petten, Member for the District of Conception Bay South. Hydro has also engaged with econext, a provincial not-for-profit industry association representing environmentally sustainable business development.

Hydro is committed to ongoing engagement and keeping our employees, the public, and other interested groups informed of progress as work moves forward. Hydro will continue to gather input throughout via the EA and regulatory application processes, and during the construction execution, commissioning and start-up phases.

4.0 Avalon Combustion Turbine Project

The proposed project to construct a new 150 MW CT, along with associated fuel storage, at the Holyrood TGS site is a large-scale project that may have varying impacts on adjacent residents, businesses, and recreationists in Conception Bay South and Holyrood area. Other stakeholder groups may also have an interest in the project with consideration to various impacts, resulting from Avalon CT the construction and ongoing operation of the Holyrood TGS.

Through the course of the early-stage engagement process for this project beginning in the second half of 2024, Hydro has issued direct communications and project information to municipal and provincial organizations and officials.

These early meetings were valuable in terms of providing planning-stage information to local Town officials, gathering initial reactions and feedback, and understanding key interests and issues.

In February 2025, open house information sessions for local residents and businesses were held in the towns of Holyrood and Conception Bay South, with a total of approximately 30 individuals in attendance. Members of both Town Councils were in attendance to receive more information directly for their own use, and to equip themselves for inquiries from residents. The open house format was self-guided, allowing attendees to drop in at any time during the event to engage with project team members, who explained project details and answered questions. Large poster boards containing project information were displayed, and information fact sheets were provided as takeaways.

Participants were also invited to contact Hydro via email with follow-up questions or information requests.

The majority of comments and questions on the project to date follow similar themes:

- *The purpose of another CT.*

  Questions were asked around whether the Avalon CT would be replacing the Holyrood TGS, or is part of Hydro's plan to decommission the plant in the future. While more generation is required to fully retire all three units at Holyrood TGS, Hydro explained that the Avalon CT project plays an important role in maintaining the reliability of the Island Interconnected System, as the Avalon CT is considered a peaking resource (i.e., being utilized primarily for capacity in times of peak energy use) that does not need to operate continuously to support the system like Holyrood TGS.

- *Use of thermal generation versus renewable energy.*

  Attendees asked why renewable energy could not be incorporated into the CT's operation. Hydro explained that engine selection criteria for the Avalon CT include the ability to utilize or be converted to renewable fuels in the future should they become available; and confirmed that more than 90% of the province's total generation will continue to be from renewable hydroelectricity. Further, the operation of Hydro's Avalon CT as a peaking resource will be compliant with *Clean Electricity Regulations*.

- *Site Location.*

  There were questions on whether Hydro considered other sites as an alternative. Hydro noted that evaluation criteria identified that building on the existing Holyrood TGS site is best to meet future demand at the lowest cost. Additionally, it allows for connection on the Avalon Peninsula, where demand is highest. The easy connection to the existing transmission line is favourable from a grid perspective, allowing for the lowest capital cost of transmission.

- *Increased emissions at the site with the addition of a new CT.*

  Information was provided about Hydro's emissions modelling to confirm that emissions are in compliance with provincial requirements, and will utilize the best available control and performance technology to improve conversion efficiency. Hydro's analysis indicates that overall emissions associated with electricity generation could be reduced by over 80% upon retirement of Holyrood TGS.

- *Other issues.*

  Other issues raised related to potential future access restrictions for surrounding ATV[1] trails; noise when the CT is in operation as well as while construction is ongoing; potential traffic disruptions; changes to the landscape with more infrastructure at the site; smell at the site; and impacts to project cost should there be schedule overruns. General inquiries included the details of the project schedule and potential employment opportunities. Hydro addressed as many of the concerns as possible and took away others for further consideration as project execution planning continues.

Open House Information Sessions on the Avalon CT Project
Holyrood and CBS

5.0 Ongoing Engagement

The feedback collected to date and going forward will be useful as Hydro develops its approach to the project and on continued information-sharing and discussion with communities and interested groups. For example, Hydro will continue to interface and communicate with the Towns to understand how potential disruption to local ATV riders may be minimized. Hydro is also actively exploring the reinstatement of the Community Liaison Committee to provide a formalized communication channel between municipal representatives and Hydro for continued engagement throughout the project lifecycle.

[1] All-terrain vehicle ("ATV").

Hydro will continue information-sharing and engagement so that members of the public and interested groups are kept informed of progress, as these projects make their way through the regulatory process, provincial EA, and the execution phase, if approved. As discussions continue, Hydro will establish those approaches, engagement opportunities, and associated schedules in collaboration with the municipalities, and other interested groups. A dedicated section of Hydro's corporate website containing information on Avalon CT and other current and planned major projects, will be publicly available in the second quarter of 2025.

Schedule 5
Attachment 1

Schedule 5, Attachment 1

Basis of Estimate

Redacted

Schedule 5, Attachment 2

Basis of Schedule

Redacted

Affidavit

IN THE MATTER OF the *Electrical Power Control Act, 1994,* SNL 1994, Chapter E-5.1 ("*EPCA*") and the *Public Utilities Act*, RSNL 1990, Chapter P-47 ("*Act*"), and regulations thereunder; and

IN THE MATTER OF an application by Newfoundland and Labrador Hydro ("Hydro") for approval of capital expenditures for the purchase, construction, and installation of Unit 8 at the Bay d'Espoir Hydroelectric Generating Facility ("Bay d'Espoir") and a combustion turbine ("CT") located on the Avalon Peninsula.

AFFIDAVIT

I, Robert Collett, of St. John's in the province of Newfoundland and Labrador, make oath and say as follows:

1) I am Vice President, Engineering and Newfoundland and Labrador System Operator for Newfoundland and Labrador Hydro, the applicant named in the attached application.
2) I have read and understand the foregoing application.
3) To the best of my knowledge, information, and belief, all of the matters, facts, and things set out in this application are true.

SWORN at St. John's in the province of Newfoundland and Labrador this 21st day of March 2025, before me:

Kimberley Duggan

Commissioner for Oaths, Newfoundland and Labrador

KIMBERLEY DUGGAN
A Commissioner for Oaths in and for
the Province of Newfoundland and Labrador.
My commission expires on December 31, 2027.

R Collett

Robert Collett