Reliability and Resource Adequacy Study 2019 Update

November 15, 2019

newfoundland labrador hydro
a nalcor energy company

A report to the Board of Commissioners of Public Utilities

newfoundland labrador
hydro
a nalcor energy company

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November 15, 2019

Board of Commissioners of Public Utilities
Prince Charles Building
120 Torbay Road, P.O. Box 21040
St. John's, NL A1A 5B2

Attention: **Ms. Cheryl Blundon**
Director of Corporate Services & Board Secretary

Dear Ms. Blundon:

Re: Reliability and Resource Adequacy Study – 2019 Update

Please find enclosed one original plus eight copies of Newfoundland and Labrador Hydro's ("Hydro") 2019 update of its Reliability and Resource Adequacy Study ("2019 Update").

Hydro filed the "Reliability and Resource Adequacy Study" on November 16, 2018 ("2018 Filing") detailing the evolution of Hydro's processes and tools, and addressing Hydro's long-term approach to providing continued least-cost, reliable service for its customers. That analysis focused on Hydro's proposed planning criteria and its ability to meet customer and system requirements reliably over a ten-year planning horizon (2019 to 2028).

The Board of Commissioners of Public Utilities' ("Board") consultant, The Liberty Consulting Group ("Liberty"), completed a comprehensive review of the 2018 filing and filed its report, "Review of Newfoundland and Labrador Hydro's Reliability and Resource Adequacy Study," with the Board on August 19, 2019 ("Liberty's Review"). Hydro has now prepared an update to the 2018 Filing. It is intended to provide additional detail on matters Hydro has continued to investigate through 2019, as well as to respond to the recommendations detailed in Liberty's Review.

As with the 2018 Filing, the 2019 Update is comprised of three volumes. Volume I outlines Hydro's Study Methodology and Proposed Planning Criteria, Volume II provides an in-depth view of near-term resource adequacy, and Volume III provides the long-term resource planning considerations, resource options available to meet the criteria proposed in Volume I, and Hydro's proposed action plan. A Summary Document is included to highlight, in brief, the key considerations of the 2019 Update.

As noted, Hydro has also responded to Liberty's recommendations throughout the 2019 Update. At the beginning of each volume of the 2019 Update is a table highlighting each of Liberty's recommendations and identifying the location of Hydro's response throughout the 2019 Update. In the Board's correspondence dated October 22, 2019, the Board requested Hydro to provide additional information regarding Liberty Recommendation #2 and #8. That information can be found at Volume III, Section 3.1 and Volume II, Section 4.2.1, respectively.

As proposed in the 2018 Filing, Hydro intends to update and file its assessment of resource adequacy annually. Hydro proposes to file a more comprehensive analysis, similar to the 2018 Filing, every three years. These reports will be complemented by annual updates, provided in years between comprehensive reviews. The intent of the annual update is to provide the Board and stakeholders with additional information on analysis conducted through the year and revised results which incorporate that analysis. Hydro intends to file a similar report in 2020 as the second annual update to the 2018 Filing. However, with respect to near-term reliability, Hydro recognizes that system reliability is top of mind for the Board and stakeholders in advance of reliable deliveries from the Muskrat Falls Generation Station. Hydro will continue to file its near-term reliability assessments semi-annually.

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

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

Yours truly,

NEWFOUNDLAND AND LABRADOR HYDRO

Shirley A. Walsh
Senior Regulatory Counsel
SAW/sk

cc: **Newfoundland Power**
Mr. Gerard M. Hayes

Consumer Advocate
Mr. Dennis M. Browne, Q.C, Browne Fitzgerald Morgan & Avis

Industrial Customer Group
Mr. Paul L. Coxworthy, Stewart McKelvey

Mr. Danny Dumaresque

ecc: **Board of Commissioners of Public Utilities**
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Ms. Roberta Frampton Benfiel
Ms. Prunelle Thibault-Bédard
Mr. Philip Raphals, The Helios Centre

Teck Resources Limited
Mr. Shawn Kinsella

List of Contents

The components of this Study include:

- Planning for Today, Tomorrow, and the Future – Summary Document
- Volume I: Study Methodology and Proposed Planning Criteria
- Volume II: Near-Term Reliability Report
- Volume III: Long-Term Resource Plan
- Abbreviations
- Definitions

PLANNING FOR TODAY, TOMORROW, AND THE FUTURE.

2019 UPDATE

newfoundland labrador hydro
a nalcor energy company

RELIABILITY & RESOURCE PLANNING: 2019 UPDATE

In 2018, Hydro completed a Reliability and Resource Adequacy Study, filed with the Board of Commissioners of Public Utilities (Board) the same year. The Study addresses our long-term approach to providing continued least-cost, reliable service for our customers. To meet customer needs, the plan considered a range of possible scenarios over a ten-year planning horizon—covering the period from 2020 through 2029.

At that time, Hydro also committed to provide the Board and stakeholders with annual updates on forecast system reliability. Hydro has proposed to file a comprehensive analysis, similar to the 2018 Study, every three years. Annual updates will be provided in the years between comprehensive reviews.

THIS YEAR'S RELIABILITY & RESOURCE ADEQUACY STUDY UPDATE FOCUSES ON THE FOLLOWING KEY CONSIDERATIONS:

1. Changes in load forecast;
2. The near-term reliability of the electricity system through the transition to Muskrat Falls being fully in-service; and,
3. Refinement of results based on recommendations made by the Liberty Consulting Group in their review of the 2018 study.

LIBERTY'S REVIEW OF THE 2018 RELIABILITY & RESOURCE ADEQUACY STUDY

Liberty was engaged by the Board to review Hydro's 2018 Study. Hydro participated in a number of face-to-face meetings, teleconferences, and provided responses to Liberty's questions throughout this process. Liberty delivered its report to the Board in August 2019; the report contained 13 recommendations, which Hydro has addressed in the 2019 update.

"Hydro performed its analysis using sound methods and tools. It applied criteria and assumptions generally appropriate in developing a robust range of supply alternatives."

– Liberty Report

ISLAND INTERCONNECTED SYSTEM

The Island Interconnected System is the interconnected portion of the Island electrical system. It is characterized by large hydroelectric generation capability located off the Avalon Peninsula, and the bulk 230 kV transmission system extending from Stephenville in the west to St. John's in the east. In 2018, the system became interconnected to North America for the first time via the Labrador-Island Link, (which connects us to the Labrador Interconnected System), and the Maritime Link, (which connects us to Nova Scotia).

LABRADOR INTERCONNECTED SYSTEM

The Labrador Interconnected System is the interconnected portion of the Labrador electrical system. Central to the system is large, hydroelectric generation capability from Churchill Falls and transmission to the two major customer centres in Labrador East and Labrador West. It is connected to the Island Interconnected System via the Labrador-Island Link. The system is also connected to the North American grid via the 735 kV AC transmission lines from Churchill Falls to Quebec.

FACTORS IMPACTING LOAD FORECAST

ELECTRICITY RATES & GROWTH IN LABRADOR

Since the 2018 study was completed, two developments have changed Hydro's baseline demand forecast for electricity requirements:

1. On the island, the Provincial Government announced additional details about their commitment to rate mitigation (to keep rates at 13.5¢/kWh).
2. In Labrador, Tacora Resources established mining operations.

These changes have increased Hydro's forecast requirements from those identified in 2018. As also observed at that time, the amount of electricity customers are projected to use depends heavily on the retail rate for electricity.

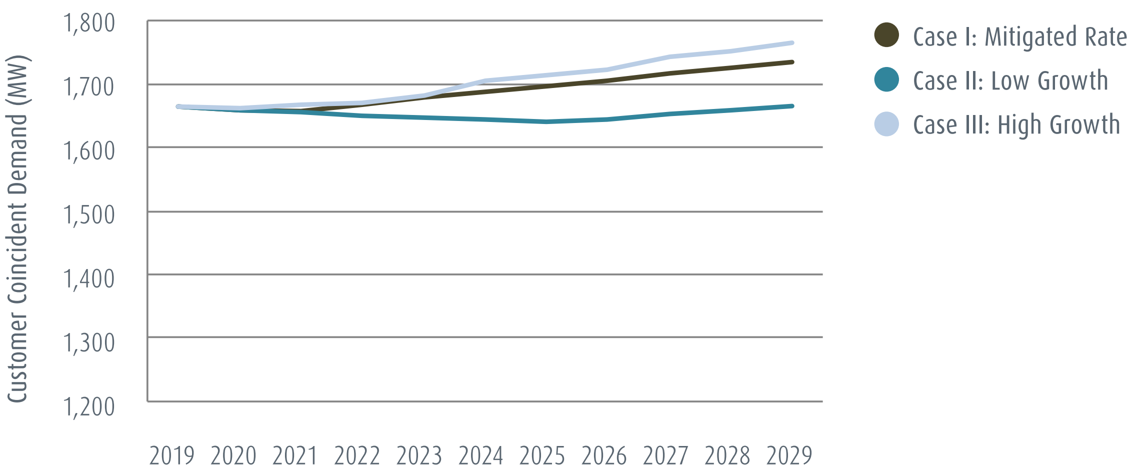
ELECTRICAL DEMAND (MW)
the maximum amount of electrical energy that is being consumed at a given time.

ANNUAL PEAK DEMAND FORECAST (MW)
the highest amount of electricity forecast to be used at one time for the year.

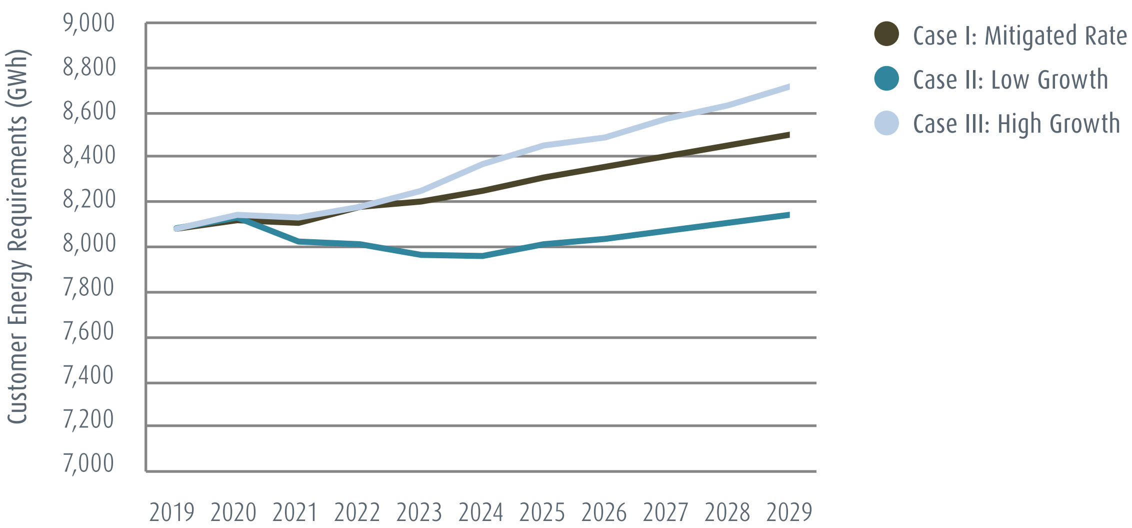
ANNUAL ENERGY FORECAST (GWh)
a forecast of how much electricity is expected to be used in an entire year.

Customer requirements are sensitive to retail electricity rates and the underlying provincial economics. In this year's study, varying these parameters can cause a difference of approximately 100 MW between the cases studied, as shown in the charts below.

Island Interconnected System Forecast Annual Peak Demand Analysis



Island Interconnected System Forecast Customer Energy Requirements



NEAR-TERM RESOURCE ADEQUACY

We are focused on our ability to meet our customers' requirements in the near term (in the next 1 to 5 years). Our assessment takes an in-depth view of system risks and mitigating measures to ensure we can reliably meet the needs of our customers through the transition to fully reliable service from Muskrat Falls and retirement of the Holyrood plant.

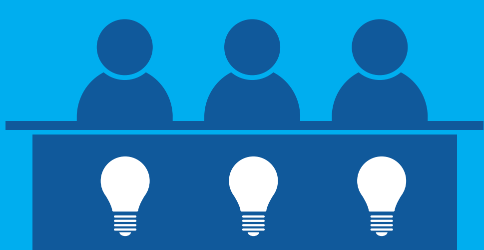
FOR 2019, THERE ARE TWO KEY FOCUS AREAS WHEN DISCUSSING NEAR-TERM RESOURCE ADEQUACY:

1. **AVAILABILITY OF THE TRANSMISSION LINE FROM MUSKRAT FALLS**
   The availability of the Labrador-Island Link (LIL) continues to be an important factor toward increasing the reliability of our system. Software issues have delayed the ability of the LIL to bring power from Labrador to the island. While we are working closely with Nalcor Energy to resolve these issues, this year's report contains detailed analysis on the reliability of the system if the LIL is further delayed.

2. **HOLYROOD THERMAL GENERATING STATION**
   Holyrood has played an important role in the Island electrical system for almost 50 years. The plant continues to be critical to system reliability until Muskrat Falls Generating Station and the LIL have proven to be reliable. Hydro continues to invest prudently in Holyrood to ensure that the plant remains reliable and has developed contingency plans that could support an additional one to two years of operation, if required.

HAVE FEEDBACK?

Join Hydro's Electricity Feedback Panel: electricityfeedbacknl.com



LONG-TERM RELIABILITY

Electricity rates are a concern for Newfoundlanders and Labradorians, and it is our responsibility to ensure the right balance between reliability and the cost of those investments for customers. While there are always options available to increase system reliability, these projects come at a cost, and can place additional pressure on electricity rates.

We value the importance of seeking customer input for consideration and decision making purposes. Customer input, along with analysis and evidence, help us make informed decisions about the future of electricity in our province.

Following our previous engagement from the 2018 Study, Hydro expects to launch a customer engagement initiative in 2020 focused on determining the value of additional reliability to customers. This work will be used to help shape Hydro's future strategy for investments in the system.

CONSIDERED SCENARIOS

Hydro examined 12 different cases as part of this year's update to the Reliability & Resource Adequacy Study. Hydro analyzed each case individually to determine which additional resources would be required in each scenario.

THREE POTENTIAL ISLAND LOAD SCENARIOS

P50 VS P90 PLANNING CRITERIA

TWO POTENTIAL LABRADOR LOAD SCENARIOS

12 DISCRETE SCENARIOS

FORECAST PROBABILITIES

A probabilistic forecast is based on the likelihood that an event will occur.

P50 FORECAST

In a P50 forecast, 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).

P90 FORECAST

In a P90 forecast, the actual peak demand is expected to be below the forecast number 90% of the time and above the forecast 10% of the time.

RESULTS

Similar to results of our 2018 analysis, Hydro is not forecasting an energy shortfall through 2029. However, based on our updated analysis, capacity shortfalls are forecast to occur in the study period, in half of the 12 scenarios considered.

The change from 2018 results is being driven by higher electricity requirements on the island, supported by lower projected electricity rates, and higher electricity requirements in Labrador, driven by increased mining activity.

Hydro has proposed to add resources when the P50 forecast identifies a requirement. Requirements for additional capacity are advanced when the P90 forecast is considered. We remain committed to working with the Board to determine the appropriate balance of investment cost and system reliability, based on these scenarios.

Capacity shortfalls requiring additional resources, within the study period, are summarized in the following table:

Island Load Case	P50 vs P90	Labrador Load Case	Year of Resource Requirements
Case I: Mitigated Rate	P90	Labrador Expected	2026
		Labrador Industrial Growth	2025
Case III: High Growth	P50	Labrador Expected	2029
		Labrador Industrial Growth	2028
	P90	Labrador Expected	2024
		Labrador Industrial Growth	2024

LOOKING AHEAD

As the utility responsible for generating the majority of the electricity for our province, it is critical that we are looking ahead and planning for tomorrow as much as today. The current update is intended to provide additional information to complement the Board's review of the Reliability & Resource Adequacy Study. We will continue to work with stakeholders and the Board through this process to determine which scenarios strike the appropriate balance of system reliability and cost.

Volume I: Study Methodology and Proposed Planning Criteria

Reliability and Resource Adequacy Study
2019 Update
Volume I: Study Methodology and Planning Criteria

November 15, 2019

A report to the Board of Commissioners of Public Utilities

Executive Summary

In 2018, Newfoundland and Labrador Hydro's ("Hydro") filed its Reliability and Resource Adequacy Study ("2018 Filing") with the Board of Commissioners of Public Utilities ("Board"). The 2018 Filing provided Hydro's long-term approach to providing continued least-cost, reliable service for its customers by establishing an action plan to meet customer demand and energy requirements in consideration of a range of scenarios. A comprehensive set of results and supporting analysis from Hydro's resource planning exercises were filed with the Board at that time. The analysis proposed changes to resource planning criteria stemming from the system changes as a result of interconnection. Proposed changes included:

- The migration to planning on a regional and sub-regional basis;
- The migration to adoption of the Loss of Load Expectation ("LOLE") target of 0.1;

This 2019 update to the Reliability and Resource Adequacy Study ("2019 Update") is filed as a complement to Hydro's 2018 Filing. It is intended to provide additional detail on matters Hydro has continued to investigate through 2019, and respond to findings and recommendations made by the Liberty Consulting Group ("Liberty") in its "Review of Newfoundland and Labrador Hydro's Reliability and Resource Adequacy Study," ("Liberty's Review") filed with the Board on August 19, 2019.

Similar to the 2018 Filing, the 2019 Update is presented as three volumes; Volume I outlines Hydro's Study Methodology and Proposed Planning Criteria, Volume II provides an in-depth view of near-term resource adequacy, Volume III provides the long-term resource planning considerations, resource options available to meet the criteria proposed in Volume I, and Hydro's proposed action plan. In the 2019 Update Hydro has also provided additional information in response to recommendations made by Liberty in its review throughout Volumes I to III. Finally, a Summary Document is included to highlight, in brief, the key considerations of the 2019 Update.

In terms of methodology and planning criteria, Hydro continues to recommend the following:

- Planning for the Newfoundland and Labrador Interconnected System on a regional and sub-regional basis;
- Continuing evaluation of supply adequacy both probabilistically and deterministically;

- Adoption of a system reserve margin that satisfies LOLE ≤ 0.1 for the Newfoundland and Labrador Interconnected System;
- Adoption of a system reserve margin that satisfies LOLE ≤ 0.1 for the Island Interconnected System;
- Maintaining sufficient operating reserve to align with NPCC operational reserve requirements; and
- Extending the existing Island Interconnected System energy criteria to the Newfoundland and Labrador Interconnected System.

With respect to the near-term reliability of the system, Hydro recognizes that supply adequacy in advance of the availability of full production from the Muskrat Falls Generating Station ("MFGS") is top of mind for its stakeholders. The enclosed assessment of near-term reliability takes an in-depth view of system risks and mitigating measures Hydro has taken to ensure its ability to reliably meet its customers through the full system transition.

Hydro closely monitors its supply-related assets to ensure its ability to provide reliable service to customers. As previously identified by both Hydro and Liberty, the availability of power over the Labrador-Island Link ("LIL") remains very important to system reliability in the near-term. Hydro is working closely with Nalcor's Power Supply leadership to monitor and mitigate the risks associated with the timing of the in-service of the LIL to supply off-Island capacity and energy to the Island Interconnected System.

The results of the longer-term reserve margin-based analysis across 12 discrete scenarios indicate that the requirement for additional resources is capacity driven and most sensitive to retail electricity rate, economic growth, and explicit use of the P90 weather variable in evaluating the requirement for incremental resources.

Similar to results from Hydro's 2018 Filing, use of the P90 peak demand forecast in evaluating the requirement for incremental resources advances investment substantially from the late 2020s to the mid 2020s. Hydro maintains that basing supply planning decisions on a P50 peak demand forecast while continuing to assess and report to the Board on forecast exposure under the P90 peak demand forecast balances system reliability and investment cost at this time. Use of the P50 peak demand forecast for supply planning would require additional resources in two cases towards the end of the ten-year study period.

Inherently the inputs for the resource planning process are not precise. Hydro has conducted its analysis consistent with practices observed across industry and while many variables, including forecast retirements and asset health for example, are analyzed to understand the implications and interaction of inputs and impacts on costs and rates, by nature these variables include uncertainty. Similar to results noted in the 2018 Filing three variables in particular contribute to the majority of variation observed between identified resource plans:

- The forecast peak demand associated with the provincial government's commitment to rate mitigation for the Island Interconnected System;
- the difference between the use of P90 versus P50 peak demand forecast in supply planning as the base for the Island Interconnected System forecast; and
- the option to mitigate the unserved energy resulting from the event that the LIL becomes unavailable for a prolonged period at a period of sustained high customer requirements when the system is peaking.

While the robust nature of the design and construction of the LIL, the anticipated asset reliability, and the anticipated required maintenance should result in a high degree of system reliability, Hydro recognizes that the Board and parties wish to better understand the implications associated with a prolonged outage of the LIL. The 2019 Update provides information regarding ongoing assessments and engineering reviews, as well as system requirements and constraints associated with the operation of the LIL. As requested, Hydro has provided additional information for the consideration of the Board and stakeholders on the expected shortfall if the LIL were to be out of service for an extended period and the amount by which the shortfall can be reduced with incremental resources.

The material provided in Hydro's 2019 update provides an opportunity for discussion with stakeholders on key decision inputs to be used in the future planning of the Newfoundland and Labrador Interconnected System. Further optimization of results will be undertaken, as required to support decision-making, and also as part of Hydro's annual planning exercise. Hydro remains committed to working with the Board and stakeholders to help ensure an appropriate balance of cost and reliability for the provincial future electrical system.

Table of Contents

List of Attachments

1.0 Introduction

1.1 Newfoundland and Labrador Interconnected System Overview

There are two primary areas or zones of electrical infrastructure in the Newfoundland and Labrador Interconnected System—the Island Interconnected System and the Labrador Interconnected System. A system map is shown in Figure 1.

The Island Interconnected System is primarily characterized by large hydroelectric generation capability located off the Avalon Peninsula and the 230 kV bulk transmission system extending from Stephenville in the west to St. John's in the east. Currently, the two largest sources of generation on the island are the Bay d'Espoir Hydroelectric Generating Facility[1] and the Holyrood Thermal Generating Station ("Holyrood TGS").[2] The Island Interconnected System is interconnected to the Labrador Interconnected System via the LIL, a 900 MW high voltage direct current ("HVdc") transmission line designed to deliver power from the MFGS in Labrador to Soldiers Pond Terminal Station on the Avalon Peninsula. The Island Interconnected System is also connected to the North American grid via the Maritime Link, [3] a HVdc transmission line connecting Newfoundland and Nova Scotia.

The Labrador Interconnected System is primarily characterized by supply at Churchill Falls and transmission to the two major load centres in Labrador East and Labrador West. The supply at Churchill Falls is provided by two sources; the TwinCo[4] Block and Recapture Energy.[5,6] As noted above, the Labrador Interconnected System is connected to the Island Interconnected System via the LIL. The Labrador Interconnected System is also connected to the North American grid via the 735 kV ac transmission lines from Churchill Falls to Québec.

[1] A 613 MW hydraulic plant on the south coast of the island.
[2] A 490 MW large oil-fired thermal generating plant located on the Avalon Peninsula.
[3] The Maritime Link is a 500 megawatt (+/- 200 kV) HVdc transmission line, as well as a 230 kV high voltage alternating current ("HVac") transmission line and associated infrastructure, connecting Newfoundland and Labrador to Nova Scotia.
[4] Twin Falls Power Corporation Limited ("TwinCo").
[5] The power referred to as the TwinCo block of power is a firm 225 MW block of power and energy, capable of supplying 1,971 GWh per year for use in Labrador West.
[6] The Recapture Energy is a source of 300 MW of capacity at a 90 percent monthly load factor available at Point A. The amount of Recapture Energy available at the Churchill Falls bus is different from the 300 MW stated at the border due to the difference in location. The original Hydro Québec 1969 Power Contract has the delivery point for the 300 MW as *"the point in Labrador on the transmission lines from the CF(L)Co Plant towards the Province of Québec which is at the height of land, about opposite present Mile 148.8 on the Québec North Shore and Labrador Railway, which is the presumed watershed between the St. Lawrence River and the Churchill River."*

Work continues on the construction and integration of the Muskrat Falls project assets, which consist of the Labrador Transmission Assets ("LTA"), the Maritime Link, the LIL, and the MFGS. Both the LTA and the Maritime Link were placed in service in 2018. It is anticipated that the LIL will deliver electricity to the Island Interconnected System in 2020. The Muskrat Falls project is expected to be fully in service by the third quarter of 2020.

Figure 1 presents an overview of the Muskrat Falls project assets, which will interconnect to form part of the Newfoundland and Labrador Interconnected System.

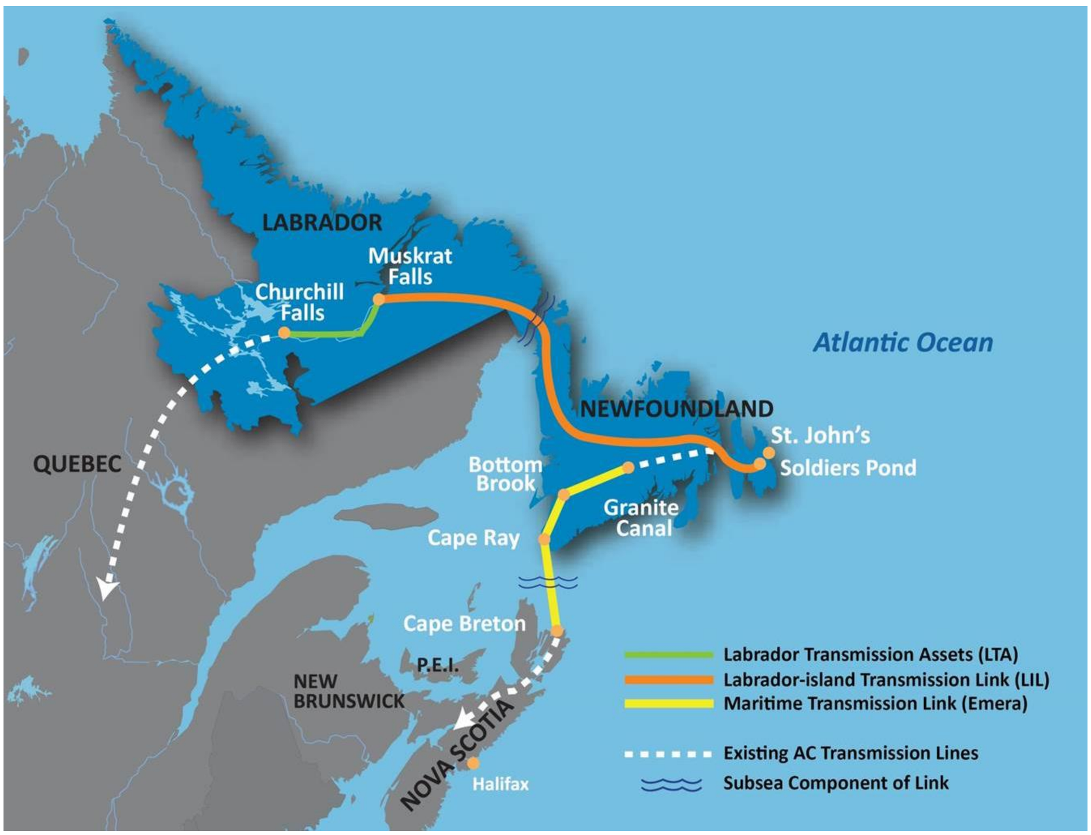


Figure 1: Muskrat Falls Project Assets

1.2 Newfoundland and Labrador Hydro's Mandate and Resource Planning

A comprehensive set of results and supporting analysis from Hydro's resource planning exercises was previously provided to the Board as part of the 2018 Filing. That analysis proposed changes to resource planning criteria stemming from the system changes as a result of interconnection. Proposed changes included:

- The migration to planning on a regional and sub-regional basis;[7] and
- The migration to adoption of the LOLE target of 0.1;

The 2019 Update is filed as a complement to Hydro's 2018 Filing. It is intended to provide additional detail on matters Hydro has continued to investigate through 2019, responses to findings and recommendations made by Liberty in its review, updates on items identified in the action plan included in Hydro's 2018 Filing, and updated identification of timing by which incremental resources are likely to be required based on the 2019 annual assessment.

System planning entails the development and assessment of supply adequacy under various potential future realities. This ensures that both sufficient capacity and energy are available to meet customer and system requirements and determines appropriate timing of requirements for additional supply. Consistent with Hydro's 2018 Filing, this analysis focused on the ability to reliably meet customer and system requirements over a 10-year planning horizon, covering the period from 2020 through 2029.[8] Operational requirements, such as operating reserve, have also been evaluated as part of the 2019 Update; refer to section 4.2.2 and Volume III for more detailed discussion.

As proposed in the 2018 Filing, Hydro intends to update and file its assessment of resource adequacy annually. Hydro proposes to file a more comprehensive analysis, similar to the 2018 Filing, every three years. These reports will be complemented by annual updates, provided in years between comprehensive reviews. The intent of the annual update is to provide the Board and stakeholders with additional information on analysis conducted through the year and revised results which incorporate that analysis. For example, in the 2019 Update, Hydro provides comment on the findings and recommendations made by Liberty in its Liberty's Review. This report is the first annual update to the 2018 Filing. Hydro intends to file a similar report in 2020, which will serve as the second annual update

[7] From a capacity planning perspective, the Island Interconnected System and the Labrador Interconnected System form a planning region called the Newfoundland and Labrador Interconnected System, and Island Interconnected System forms a sub-region. For additional detail, please refer to Hydro's 2018 Filing.
[8] Reporting on a ten-year planning horizon is observed in the "2017 Long-Term Reliability Assessment," North American Electric Reliability Corporation, March 1, 2018.
<https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_12132017_Final.pdf>

to the 2018 Filing. However, with respect to near-term reliability, Hydro recognizes that system reliability is top of mind for the Board and stakeholders in advance of reliable deliveries from the MFGS. Hydro will continue to file its near-term reliability assessments semi-annually.

From a capacity perspective, in accordance with industry practice, both probabilistic and deterministic assessments of adequacy were completed. Probabilistic assessments use statistical analysis of system performance and projected supply availability, e.g., forced outage rate ("FOR"), and simulate system behaviour to determine the resultant forecast system reliability. This provides an indication of the likelihood that all demand will be served. Deterministic analysis evaluates the contribution of individual system elements to overall system reliability. This provides the ability to test system resiliency in consideration of different contingencies or outage events. The use of differing complementary methods offers a robust analysis of system adequacy. It is recommended that supply adequacy continue to be assessed on the basis of both probabilistic and deterministic supply adequacy criteria.

From an energy perspective, Hydro completed an assessment of its ability to meet firm energy requirements in consideration of firm hydraulic energy sequences.[9]

2.0 Consideration of Liberty's Review and Recommendations

Throughout 2019, Liberty conducted a thorough review of Hydro's 2018 Filing. The review consisted of initial documentation review, on-site interviews, and independent analysis. While Liberty's Review proposed a number of recommendations, generally Liberty was supportive of much of the work Hydro completed, stating:

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

> ***"While we recommend testing and validation, and adjustment if thereby warranted, of some methods and criteria, none of our recommendations undercut the value of using the current analysis as a foundation for examining supply reliability risks, consequences, and solutions."[10]***

Hydro has reviewed the report from Liberty's Review and Table 1 highlights each recommendation and where Hydro's response can be found within the 2019 Update. This table is located at the beginning of each volume of the 2019 Update for ease of reference. Recommendations in bold indicate that Hydro's response to Liberty's recommendations can be found in the particular volume of the Study.

Table 1: Location of Responses to Liberty's Recommendations

Item	Recommendation	Location in the 2019 Update
Study Methods, Assumptions, and Criteria		
1a	Hydro should promptly examine the likelihood and the range of consequences of an extended bipole LIL outage under extreme weather circumstances,	Vol. III, s 7.2.1
1b	and should undertake a robust examination of generation options (including continued use of the Holyrood steam units) to mitigate that risk.	Vol. III, s 5.6.1
2	Hydro should promptly commence a stakeholder engagement process to address Value of Loss Load ("VOLL"), informed by a sound contemporaneous examination of extended bipole outage risk and the options, including extension of generation at Holyrood, for mitigating that risk.	Vol. III, s 3.1
3	**Hydro should continue to reflect both P50 and P90 weather conditions as part of its efforts to assess system reliability and economy as it acquires more information in the coming months.**	**Vol. I, s 4.2.4**
4	**Hydro should verify that its means for addressing the relationship between planning and operating reserve margins does not introduce significant error.**	**Vol. I, s 4.2.1**
5	**Hydro should promptly analyze whether differences in its system and those of Manitoba Hydro and Hydro Quebec have any implications for benchmarking its planning reserve margin.**	**Vol. I, s 6.5.1**
Long-Term Reliability		
6	**Hydro should establish a plan and schedule for integrating the results of the current examination and subsequent processes for considering factors affecting future electrical requirements and non-generation means for**	**Executive Summary**

[10] "Review of Newfoundland and Labrador Hydro's Reliability and Resource Adequacy Study," The Liberty Consulting Group, August 19, 2019 at p. 17.

Item	Recommendation	Location in the 2019 Update
	influencing load and usage into a re-analysis of its future needs under a robust range of circumstances and scenarios.	
7	Promptly conduct the analyses necessary to assess short-term and indefinite extension of Holyrood's life as a supply reserve.	Vol. III, s 4.1.1
Near-Term Reliability		
8	Immediately conduct a detailed assessment of the impacts of a delay in LIL operation into and past the coming winter.	Vol. II, s 4.2.1
9	Resolving the issues that have surrounded LIL monopole availability should continue to form a critical focus and Hydro should ensure that longer-term uncertainties about Holyrood's future do not lead to decisions that compromise its ability to operate reliably now.	Vol. III, s 4.1.1
Extended LIL Outages		
10	Hydro should conduct a detailed analysis quantifying the probabilities and restoration durations for a robust range of bipole LIL outages.	Vol. III, s 7.2.1
11	Hydro should complete remaining steps to prepare for LIL outages as soon as possible.	Vol. III, s 7.2.1
Generation Asset Reliability		
12	Engage an entity with substantial experience in boiler construction and repair to conduct a detailed assessment of Holyrood's major systems.	Vol. III, s 5.6.1

With respect to recommendation #13, Hydro appreciates Liberty's suggestions for further enhancements to its asset management processes. Hydro is considering items noted by Liberty for inclusion in its asset maintenance program.

3.0 Overview of the Resource Planning Process

Figure 2 is a flowchart that provides a visual representation of Hydro's resource planning process. Please refer to the 2018 Filing, Volume I, section 1.3 for a comprehensive overview of the resource planning process. While the process outlined in Figure 2 details Hydro's traditional approach to resource planning, the impact of rates following the in service of the Muskrat Falls project assets requires the approach to be modified to support development of additional information likely pertinent to the "Reference on Rate Mitigation Options and Impacts Relating to the Muskrat Falls Project Costs" ("Reference Question").[11]

[11] "Reference on Rate Mitigation Options and Impacts Relating to the Muskrat Falls Project Costs," Newfoundland and Labrador Board of Commissioners of Public Utilities, Media Release, October 16, 2018.

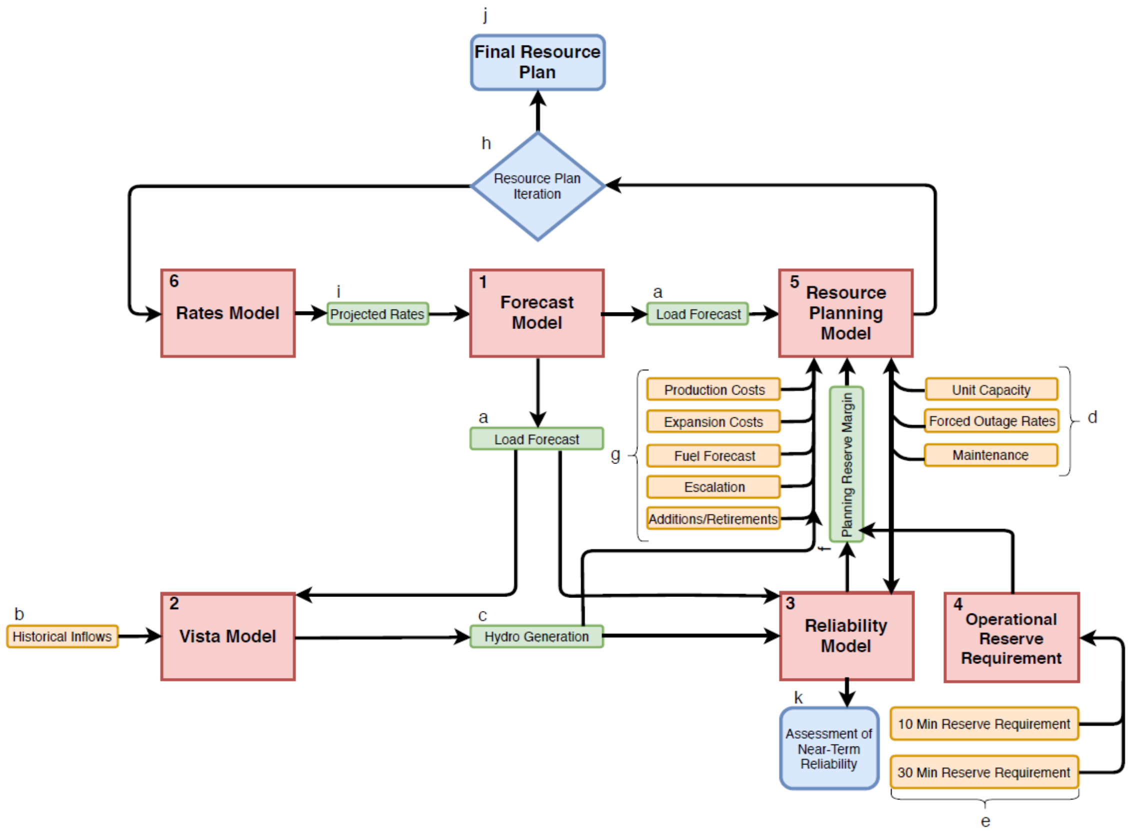


Figure 2: Resource Planning Process Flowchart

3.1 Liberty's Review

As part of its review, Liberty conducted extensive examination of the process and methods by which Hydro examined its future electrical requirements and means for meeting them. Liberty's Review concluded the study process described in the 2018 Filing to be fairly conventional, stating:

<http://www.pub.nf.ca/2018ratemitigation/notices/Media%20Release%20-%20Rate%20Mitigation%20Options%20and%20Impacts%20-%20FINAL%20-%202018-10-16.pdf>

> ***"Our review of documents detailing the inputs and outputs of the key components found capable execution of a logical and comprehensive process. We found the improvements largely responsive to the past concerns we have raised about Hydro's supply planning."*** [12]

4.0 Proposed Planning Criteria

Resource planning activities are generally focused on satisfying an adopted loss of load criteria while ensuring sufficient resources to meet operational reserves. Loss of load metrics provide a probabilistic assessment of system reliability. This helps to quantify the likelihood that a utility will not be able to meet its demand requirements at a point in time, considering numerous potential operating scenarios that can occur.[13] In other words, loss of load metrics evaluate the instances in which system demand exceeds the available generating capability. There are four generally accepted types of probabilistic metrics against which system reliability is measured:

1) Loss of Load Probability ("LOLP");
2) Loss of Load Expectation ("LOLE");
3) Loss of Load Hours ("LOLH"); and
4) Expected Unserved Energy ("EUE").

While interpretation of the measures varies across jurisdictions, definitions contemplated herein are consistent with guidelines established by the North American Electricity Reliability Corporation ("NERC")[14], which state: [15]

- **LOLP:** The probability of system daily peak or hourly demand exceeding available generating capacity in a given study period.

[12] "Review of Newfoundland and Labrador Hydro's Reliability and Resource Adequacy Study," The Liberty Consulting Group, August 19, 2019 at pg. 4
[13] Loss of Load refers to instances where some system load is not served.
[14] NERC is a non-profit, self-regulating organization with an objective to ensure adequate reliability of the bulk power system in North America. NERC develops and enforces reliability standards, including guidelines for long-term resource planning. The North American bulk power system is divided into eight regions, encompassing all of the United States and Canada, with the exception of Newfoundland and Labrador.
[15] "Probabilistic Assessment Technical Guideline Document," North American Electric Reliability Corporation, August 2016. <https://www.nerc.com/comm/PC/PAITF/ProbA%20Technical%20Guideline%20Document%20-%20Final.pdf>

- **LOLE:** The expected number of days each year where available generation capacity is insufficient to serve the daily peak demand.
- **LOLH:** The expected number of hours per year when a system's hourly demand is projected to exceed the generating capacity. This metric is calculated using each hourly load in the given period (or the load duration curve) instead of using only the daily peak in the LOLE calculation.
- **EUE:** The expected amount of demand (expressed in MWh or parts per million) that is unserved per year due to demand exceeding generating capacity.

4.1 Summary of Criteria Review Conducted

4.1.1 Pre-Existing Planning Criteria

System supply investment prior to 2018 has been based on previously established resource planning criteria, detailed as follows:

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

Additionally, Hydro maintained operational reserves of no less than 240 MW on the Island Interconnected System. This 240 MW reserve margin provides the ability to meet current operational reserve requirements.[16]

As discussed in Volume I, section 3.1 of the 2018 Filing, the existing criteria will continue to be applied until full integration of the Muskrat Falls project assets (planned third quarter of 2020). With the new transmission interconnection to the North American grid, there is a need to better understand how reliability expectations compare to those of other interconnected utilities and the implications for reserve requirements and the resulting supply adequacy.

[16] Operationally, the system requires the ability to withstand the loss of the single largest resource (typically the loss of the Holyrood TGS Unit 1 or 2, or Bay d'Espoir Unit 7) while maintaining an additional reserve of 70 MW.

4.2 Proposed Reliability Criteria

Many utilities throughout Canada and across North America have adopted reliability metrics that follow guidelines established by NERC. Hydro continues to recommend modifications to both the probabilistic and deterministic capacity planning criteria to bring reliability metrics used in the jurisdiction more in line with those commonly used across North America. Detailed information on the analysis conducted and development of Hydro's proposed criteria can be found throughout Volume I of the 2018 Filing. A summary of Hydro's proposed criteria for the Newfoundland and Labrador Interconnected System follows:

4.2.1 Probabilistic Capacity Planning Criterion

Hydro has proposed that both the Newfoundland and Labrador Interconnected System (region) and the Island Interconnected System (sub-region) should each have sufficient generating capacity to satisfy a LOLE target of not more than 0.1.

Liberty's Review and Recommendations

Hydro maintains that the adoption of the LOLE metric with the target of LOLE $\leq$ 0.1 increases planned system reliability from that which would be planned using the pre-existing probabilistic criterion of LOLH $\leq$ 2.8. This is echoed in the Liberty Review which states:

> ***"Hydro's change from a criterion of LOLH ≤ 2.8 to LOLE ≤ 0.1 produces a larger level of required reserves, and a corresponding increase in reliability."***[17]

Liberty's Review correctly observed that Hydro's use of the reliability indices in the 2018 Filing assumed that, in a shortage event, firm load will not be curtailed until load exceeds available generating capacity. It went on to observe that in reality, some amount of operating margin must be maintained to ensure system stability, noting in the current system Hydro requires 70 MW of such reserve.[18]

[17] "Review of Newfoundland and Labrador Hydro's Reliability and Resource Adequacy Study," The Liberty Consulting Group, August 19, 2019 at p. 18.
[18] "Review of Newfoundland and Labrador Hydro's Reliability and Resource Adequacy Study," The Liberty Consulting Group, August 19, 2019 at p. 18.

Liberty's Recommendation #4:

"Hydro should verify that its means for addressing the relationship between planning and operating reserve margins does not introduce significant error."[19]

Hydro agrees with Liberty's recommendation and has implemented a minimum operational reserve in its Reliability Model. Hydro has determined that the required amount of such operational reserve required to be held on the system differs based on whether or not the LIL is in-service. The LIL is designed with constant frequency control. This enables the system to operate with a lower operational reserve as the LIL is able to provide frequency regulation. Hydro has preliminarily defined a minimum operating reserve of 35 MW for when this controller is in service. This is subject to further review once LIL is in service with full functionality at rated capacity.

Hydro proposes to maintain a minimum reserve of 70 MW within the island system when the LIL is out of service to provide for acceptable frequency regulation as presented in "TP-TN-068 - Application of Emergency Transmission Planning Criteria for a LIL Bipole Outage." [20] This requirement is also now incorporated in Hydro's Reliability Model.

4.2.2 Operational Reserve Requirements

The Maritimes assessment area[21] is included as one of the eight regions governed by the Northeast Power Coordinating Council ("NPCC").[22] The NPCC requirements state that compliant utilities will ensure that:[23,24]

- "Each Balancing Authority shall have **ten-minute reserve** available to it that is at least equal to its **first contingency loss**."; and

[19] "Review of Newfoundland and Labrador Hydro's Reliability and Resource Adequacy Study," The Liberty Consulting Group, August 19, 2019 at p. 23.
[20] Filed with the Board July 31, 2019.
[21] The Maritimes assessment area is comprised of New Brunswick, Nova Scotia, and Prince Edward Island, and the northern portion of Maine, which is radially connected to the New Brunswick power system.
[22] NPCC is a regional entity division which operates under a delegation agreement with the NERC.
[23] The Balancing Authority is defined by NERC as the responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within a Balancing Authority Area, and supports Interconnection frequency in real time.
[24] "Regional Reliability Reference Directory # 5 Reserve," NPCC, September 27, 2019. <https://www.npcc.org/Standards/Directories/Directory%205%20-%20Reserve_20190930.pdf >

- "Each Balancing Authority shall have **thirty-minute reserve** available to it that is at least equal to one-half its **second contingency loss**."

In the Newfoundland and Labrador Interconnected System, Hydro considers the first contingency loss to be the loss of a generating unit at MFGS and the second contingency loss to be the loss of a second unit at MFGS. As such, Hydro will plan for the availability of the following operational reserves for the Newfoundland and Labrador Interconnected System to align with this criteria:[25,26]

- **Ten-Minute Reserves:** Hydro shall have 10-minute reserve available to it at least equal to 197.5 MW to cover its first contingency loss, where the first contingency loss is the loss of a unit at the MFGS at winter firm plant output of 790 MW.
- **Thirty-Minute Reserves:** Hydro shall have 30-minute reserve available to it at least equal to 99 MW to cover one-half the magnitude of its second contingency loss (0.5 × 197.5 MW), where the second contingency loss is the loss of a unit at the MFGS at winter firm plant output of 790 MW.

In consideration of the operational reserve requirements, a total operational reserve margin of at least 296.5 MW must be available for the Newfoundland and Labrador Interconnected System.[27]

Liberty's Review and Recommendations

Liberty reviewed the level of operational reserve requirements proposed by Hydro and determined them to be reasonable on a provincial basis, subject to its continued concerns over the consequences of a bipole LIL outage. Liberty identified that whether the first contingency was the loss of a unit at MFGS or the loss of a single pole of the LIL, required operational reserves would be generally the same to cover the first contingency.[28] Liberty stated:

[25] For additional information about the winter firm plant output of the MFGS, please refer to section 4.2.2.3 of the 2018 Filing.
[26] This is based on the per unit contribution to the firm plant output of the MFGS (790 MW).
[27] The addition of the 10-minute reserve requirement (197.5 MW) and the 30-minute reserve requirement (99 MW) yields a reserve requirement of 296.5 MW.
[28] Reserves required to cover the loss of the one unit at the MFGS would be 197.5 MW based on a firm winter plant capacity of 197.5 MW. Reserves required to cover the loss of one pole of the LIL would be 225 MW less associated losses when no exports scheduled over the Maritime Link and less when Maritime Link exports are non-zero.

> ***"We found Hydro's operational reserve requirement of 296.5 MW, based on Muskrat Falls units as the largest contingencies, sound on a province-wide basis, subject to concerns about the consequences of a bipole LIL outage."[29]***

Liberty explains that if the largest contingency is determined to be the bipole outage, operational reserves would need to be significantly increased if the intent is to support 10- and 30-minute reserves as previously defined. This would result in significant incremental costs within the jurisdiction that must be balanced against the incremental reliability such investment would provide. Additional information on the reliability of the LIL and potential consequences of prolonged bipole outage is provided in section 7.2 of Volume III of the 2019 Update.

4.2.3 Energy Criterion

A review of the system energy capability and forecast requirements have resulted in the recommendation to extend the existing energy planning criteria to cover the entire Newfoundland and Labrador Interconnected System, as follows:

- **Energy:** The Newfoundland and Labrador Interconnected System should have sufficient generating capability to supply all of its firm energy requirements with firm system capability.

Further detail can be found in Volume I, section 3.3 of the 2018 Filing.

Liberty's Review and Recommendations

Liberty reviewed the proposed energy criterion and found it to be appropriate, stating:

> ***"This criterion, which we find standard and appropriate, requires no additional margin above firm energy requirements."[30]***

[29] "Review of Newfoundland and Labrador Hydro's Reliability and Resource Adequacy Study," The Liberty Consulting Group, August 19, 2019 at p. 19.
[30] "Review of Newfoundland and Labrador Hydro's Reliability and Resource Adequacy Study," The Liberty Consulting Group, August 19, 2019 at p. 6.

4.2.4 Additional Consideration: The P90 Peak Demand Forecast in Supply Planning

In the 2018 Filing, Hydro proposed the P90 peak demand forecast continue to be evaluated from a planning perspective, but that resource additions be planned on a P50 peak demand forecast basis. Hydro's probabilistic assessment of resource adequacy includes a load forecast uncertainty parameter that allows consideration of the full range of forecast variation driven by weather. This ensures that when evaluating its P50 forecast, the impact that weather variability can have on the expected peak is considered through application of the load forecast uncertainty multiplier. This treatment is consistent with practices observed across industry. Note that the resultant determination of planning reserve margin includes consideration of load variability resulting from all weather conditions (i.e., P01 through P99) with the results applied as a variation from the mean forecast value (i.e., P50). This new method for assessing load forecast uncertainty increases the conservatism embedded in forecast modelling compared to modelling only the P50 and P90 discretely.

Liberty's Review and Recommendations

Liberty's Review noted that Hydro has continued to depict results under both P50 and P90 peak demand forecasts, observing that the approach helps to inform the process of deciding what reliability enhancements merit investment.[31]

Liberty's Recommendation #3:

Hydro should continue to reflect both P50 and P90 peak weather conditions as part of its efforts to assess system reliability and economy as it acquires more information in the coming months."[32]

Hydro agrees with Liberty's assertion that the use of a P50 forecast for resource planning, while recognizing the consequences of P90 circumstances, provides an appropriate baseline for looking at the uncertainties affecting Hydro's system. Hydro proposes to continue to use P50 as the basis of its modelling exercises and the P50 peak demand forecast as the baseline for its planning analysis and provide analysis on the P90 peak demand forecast. This will provide stakeholders with an important

[31] "Review of Newfoundland and Labrador Hydro's Reliability and Resource Adequacy Study," on August 20, 2019, The Liberty Consulting Group, August 19, 2019 at p. 14.
[32] "Review of Newfoundland and Labrador Hydro's Reliability and Resource Adequacy Study," on August 20, 2019, The Liberty Consulting Group, August 19, 2019 at p. 22.

understanding of the incremental risk that can exist in the event of extreme weather and how the system is positioned to withstand contingencies. This information can help provide information for Hydro, the Board, and stakeholders to determine if the incremental investment is justified in the jurisdiction at that time.

In Liberty's Review, it was further noted that given Hydro's Reliability Model incorporates weather uncertainty, it is important that any P90 assessment does not duplicate the weather effects associated with the P90 extreme weather condition. In cases where incremental resources have been identified as required based on a P90 peak demand forecast, Hydro believes that this analysis does include some amount of duplication of the impact of the P90 forecast, as it is included inherently in the Reliability Model and explicitly in consideration of the P90 peak demand. Hydro will also track and report on the frequency of weather conditions that occur between P50 and P90 expectations and above P90 to monitor when or whether changes are necessary.

5.0 Study Methodology

5.1 Summary of Hydro's Modelling Approach

The study analysis, including the development of the PLEXOS® model,[33] was conducted in accordance with the most recent version of the NERC "Probabilistic Assessment Technical Guideline Document"[34] and the NERC "Reliability Assessment Guidebook"[35] to ensure alignment with industry accepted practice. Processes and guidelines from both documents were used to inform the planning process.

The NERC "Reliability Assessment Guidebook" notes that typically, upon completion of probabilistic adequacy assessments, the results are translated into a planning reserve margin. This planning reserve margin can then be used as a reliability metric to evaluate the system's resource adequacy. A detailed hourly system model ("the Reliability Model") using Monte Carlo simulation was implemented in

[33] For additional information as to why Hydro migrated from the Strategist Modelling Platform to the PLEXOS® Modelling Platform, see Volume I, attachment 4 "Migration to the PLEXOS® Modelling Platform," Newfoundland and Labrador Hydro's "Reliability and Resource Adequacy Study," filed on November 16, 2018.
[34] "Probabilistic Assessment Technical Guideline Document," North American Electric Reliability Corporation, August 2016. <https://www.nerc.com/comm/PC/PAITF/ProbA%20Technical%20Guideline%20Document%20-%20Final.pdf>
[35] "Reliability Assessment Guidebook," North American Electric Reliability Corporation, Version 3.1, August 2012. <https://www.nerc.com/comm/PC/Reliability%20Assessment%20Subcommittee%20RAS%20DL/Reliability%20Assessment%20Guidebook/Reliability%20Assessment%20Guidebook%203%201%20Final.pdf>

PLEXOS® to determine an appropriate planning reserve margin to satisfy the proposed reliability criteria,[36] consistent with practices in other jurisdictions. This planning reserve margin is then used in the utility's long-term resource planning process. The resultant target planning reserve margin is presented in section 6. Further information on the resulting proposed long-term resource plan is found in Volume III: Long-Term Resource Plan.

While long-term investment requirements will be identified using the planning reserve margin process, this process will be complemented by the evaluation of near-term supply adequacy as identified required investments progress from a longer term planning horizon to the near-term planning horizon. By using this methodology, the potential for resource shortfalls will be identified well in advance, leaving adequate time to plan and construct or secure the least-cost resource option. The granular near-term view provides insight into the impact of seasonal load and generation variations on supply events. This can be used to further inform the decision on which resource options are best suited to meet evolving system requirements.

5.2 Modelling Assumptions

Figure 3 is a representation of the Newfoundland and Labrador Interconnected System model. It is a simplified display of the way in which each region is connected within the provincial zone and to the external markets, Québec and Nova Scotia, with arrows indicating the possible flow of energy.

[36] Hydro's proposed reliability criteria are discussed in section 4.2.

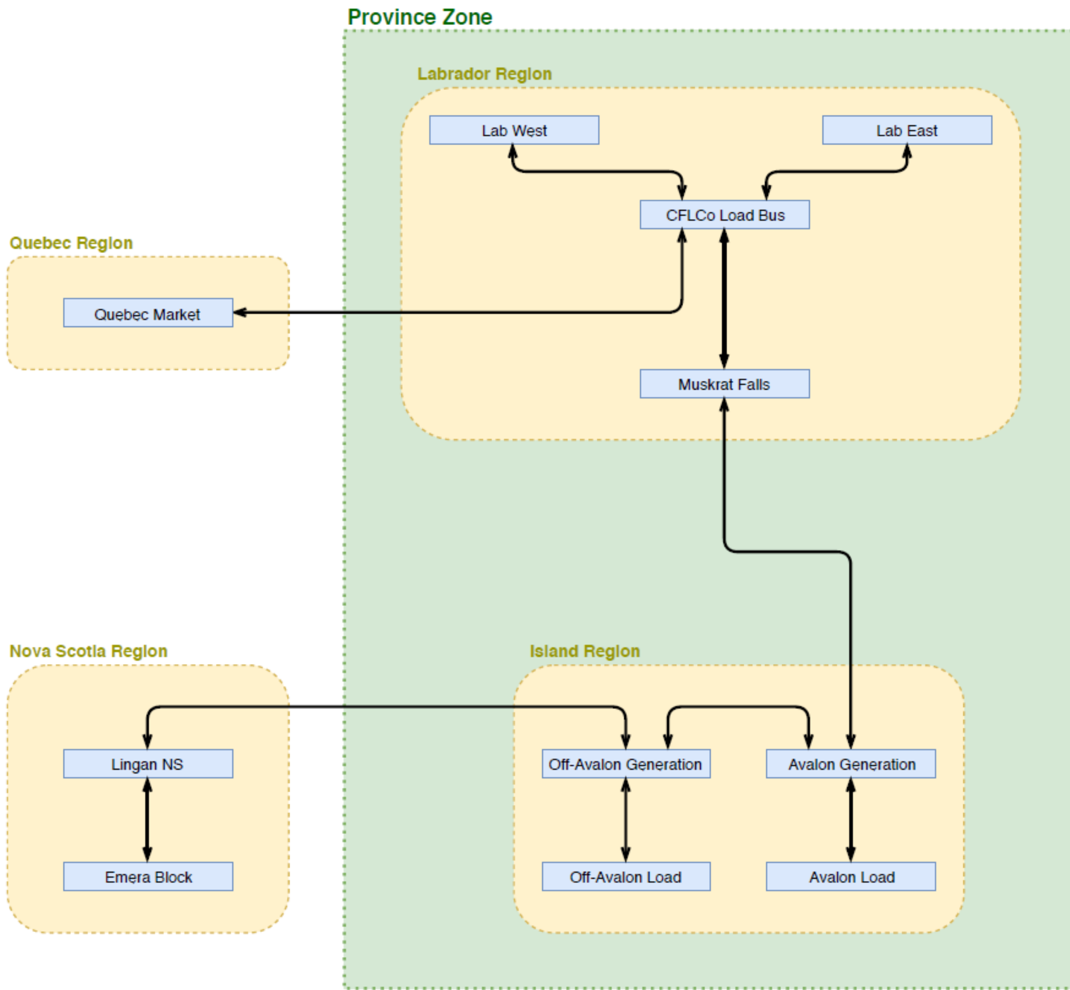


Figure 3: Newfoundland and Labrador Model Topography

The methodology surrounding development of each component of the Newfoundland and Labrador Interconnected System in the Reliability Model including the load modelling, capacity modelling by asset class, transmission modelling, and market modelling are discussed extensively in the 2018 Filing, Volume 1, section 4. Any changes to the inputs and assumptions since the 2018 Filing are discussed in the following subsections. Summaries of detail provided in the 2018 Filing are provided for sections with inputs and assumptions that have not had a material change in methodology. Sections that have been expanded on since the 2018 Filing are discussed in detail.

5.2.1 Key Inputs into the Reliability Model:

- Load Modelling: no change in methodology from 2018 Filing;

- Capacity Modelling: expanded modelling of Muskrat Falls hydrology;
- Variable Energy Resources: update to effective capacity of wind generation;
- Capacity Transfers: Imports and Exports – no change in methodology from 2018 Filing;
- Transmission Modelling: no change in methodology from 2018 Filing; and
- Emergency Operating Procedures: no change in methodology from 2018 Filing.

5.2.2 Load Modelling

The load forecast is a key input to the resource planning process which projects electric power demand and energy requirements through future periods. The Newfoundland and Labrador Interconnected System load forecast is segmented by the Island Interconnected System and Labrador Interconnected System and rural systems, as well as by utility load (i.e., domestic and general service loads of Newfoundland Power and Hydro) and industrial load (i.e., larger direct customers of Hydro such as Corner Brook Pulp and Paper Limited., North Atlantic Refining Limited., Vale Newfoundland and Labrador Limited, and the Iron Ore Company of Canada). The load forecast process entails translating a long-term economic and energy price forecast for the province into corresponding electric demand and energy requirements for the electric power systems. The load forecasts for the Island Interconnected System and Labrador Interconnected System were prepared during the spring and summer of 2019. Please refer to the 2018 Filing, Volume I, section 4.2.1 for additional detail.

5.2.3 Load Modelling: Load Forecast Uncertainty

Load forecast uncertainty models how a system's peak load can vary from the forecast peak load by providing an uncertainty range to the load forecast. A Load Forecast Uncertainty parameter[37] is applied against the expected peak demand, that is, the P50 peak demand forecast for the area.[38] Both potential economic variability and weather variability uncertainty have been incorporated in the planning process. A range of economic conditions were considered in the development of long-term resource plans, while probabilistic modelling of weather variability was considered in setting the planning reserve margin.

[37] Load Forecast Uncertainty is a multiplier representing the potential variance in annual peak demands. Its value is based on a distribution of expected values of load based upon an analysis of the weather sensitivity of peak loads.
[38] "Reliability Assessment Guidebook," North American Electric Reliability Corporation, Version 3.1, August 2012. <https://www.nerc.com/comm/PC/Reliability%20Assessment%20Subcommittee%20RAS%20DL/Reliability%20Assessment%20Guidebook/Reliability%20Assessment%20Guidebook%203%201%20Final.pdf>

Hydro's analysis was complemented by a detailed external review by Daymark Energy Associates. Please refer to the 2018 Filing, Volume I, section 4.2.1 for additional detail.

Liberty's Review and Recommendations

Liberty noted that Hydro's load modelling disaggregated load in an appropriate manner and considered a range of economic and electricity price conditions, which resulted in a reasonable number of scenarios. It was further observed that the scenarios considered resulted from methods and criteria generally consistent with common industry approaches.

While Liberty made no recommendations on the mechanics underlying Hydro's load forecast, Liberty observed that the linkage of the outcome of the Reference Question and its eventual impact on utility planning, particularly with respect to demand elasticity, must form part of continued discussion with stakeholders.

> ***"Hydro's forecasts provide a sound basis for framing the needed continuation of discussions about future supply resource needs, but those discussions need to accommodate information, analysis, and stakeholder engagement that will become available in the next coming months."*** [39]

Additional detail on Hydro's most recent forecasts and proposed stakeholder engagement can be found is provided in Volume III of the 2019 Update.

5.2.4 Capacity Modelling

To ensure accurate modelling of its supply resources, Hydro incorporated detailed modeling of its capacity resources and power purchase agreements, incorporating probabilistic analysis. Please refer to the 2018 Filing, section 4.2 for further details.

Since the November 2018 filing Hydro has expanded the method it uses to model Muskrat Falls hydrology. In the previous model Hydro based its analysis on five annual generation profiles for the MFGS. In the current methodology Hydro has developed monthly generation probability curves for the

[39] "Review of Newfoundland and Labrador Hydro's Reliability and Resource Adequacy Study," The Liberty Consulting Group, August 19, 2019 at p. 14.

MFGS using 38 years of inflow data from 1978–2016. Using a larger dataset allows Hydro to account for a more complete range of potential inflow scenarios.

Liberty's Review and Recommendations

Liberty conducted an extensive review of how Hydro modelled its supply resources. Liberty concluded that the modelling employed a sound foundation for assumptions about unit availability and outages and credible planning assumptions about the future operation of its generating stations.

> ***"Hydro modelled future system reliability using an industry-standard tool across a range of load forecasts, using soundly based expectations about unit performance and hydrological conditions."[40]***

5.2.5 Variable Energy Resources

Analysis of Effective Wind Capacity

In its 2018 Filing, Hydro included analysis of the contribution of wind generation to the reliability of its system to consider the effective contribution of wind generation to meet peak demand from a planning perspective.[41] This preliminary work was expanded through 2019 following conversations with Liberty and additional industry analysis conducted internally. The 2019 Update includes two discrete areas of focus:

1) To determine the effective capacity of the existing wind generation facilities on the Island Interconnected System; and
2) To separately estimate the capacity of new wind generation when considered as a resource option.

In its expanded analysis, Hydro conducted an Effective Load Carrying Capability ("ELCC") study, a Cumulative Frequency Analysis ("CFA"), and considered the impact of external factors including:

- Correlation and coincidence of existing and potential future sites;

[40] "Review of Newfoundland and Labrador Hydro's Reliability and Resource Adequacy Study," The Liberty Consulting Group, August 19, 2019 at p. 17.
[41] Refer to the "Reliability and Resource Adequacy Study," Newfoundland and Labrador Hydro, Newfoundland, vol. I, s 4.2.3.1 at p.36; filed November 16, 2018.

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

Combining this analysis with a study of the approaches used in other jurisdictions, Hydro proposes to maintain the capacity contribution of existing and incremental wind generation sources at 22%. The use of 22% was also agreed upon with parties as part of Hydro's most recent Cost of Service Methodology Review and is before the Board for approval.[42] A report containing the details of Hydro's analysis is included in attachment 1.

Liberty's Review and Recommendations

Liberty reviewed Hydro's proposed treatment of wind generation and noted that the use of the same distribution for each hour could overlook any variation in mean wind generation over the day. It was further observed that given the small total amount of wind generation on the system, the treatment has little impact on overall results.

Hydro believes the analysis presented in attachment 1 addresses the underlying concerns. Hydro agrees that the treatment of wind generation from an effective capacity contribution does not materially change results given the low penetration and relatively small contribution of wind generation as compared to other supply sources. Hydro has committed to further evaluation of the contribution of wind as a resource should penetration increase or should wind emerge as a preferred resource option.

5.2.6 Capacity Transfers: Imports and Exports

Firm imports and exports are considered as part of Hydro's modelling, consistent with NERC standard practice to ensure capacity is not double counted between jurisdictions. Exports are added as a load and imports are treated as a reduction in load. The contractual requirements are used to derive an hourly profile for the exports or imports.

[42] The "Cost of Service Methodology Review Application" was filed by Hydro with the Board on November 15, 2019. A Settlement Agreement regarding the Cost of Service Methodology Review was filed on October 10, 2019 and is currently under review by the Board.

There are two commitments for firm exports; a commitment for firm capacity ("Nova Scotia Block"), and a commitment for firm energy ("Supplemental Energy"). The Nova Scotia Block is a firm annual commitment of 980 GWh, to be supplied from the MFGS on peak. The Supplemental Energy is a commitment to supply additional firm energy to Nova Scotia during the first five years of production at the MFGS as part of the "Amended and Restated Energy and Capacity Agreement."[43]

Hydro does not currently have long-term firm import contracts in place, although the possibility could exist at some point in the future.

Currently, non-firm imports are not considered in the reliability analysis. This is a conservative approach to maintaining the adequacy of provincial supply.

5.2.7 Transmission Modelling

Hydro's Reliability Model includes a simplified representation of the bulk transmission system to ensure the system is capable of delivering electricity to meet customer requirements and that all known constraints are appropriately considered as part of the resource planning process. Hydro's Reliability Model separates the Newfoundland and Labrador Interconnected System into two zones linked by transmission, the Island Interconnected System region and the Labrador Interconnected System region, with the LIL connecting the two. Zones are further divided into sub-regions e.g., Avalon, Off-Avalon, Lab-West, Lab-East) linked by the bulk transmission network, inclusive of appropriate constraints. There are also two external regions modelled, representing the two connections to external markets via Québec and Nova Scotia. The transfer capability of each transmission line is included in the Reliability Model. Figure 3 in section 5.2 of this report provides a visual representation of the Newfoundland and Labrador Model Topography.

Transmission constraints were identified in section 4.2.5 of the 2018 Filing associated with the existing exposure to a three phase fault at the bus of the Bay d'Espoir Hydroelectric Generating Facility. These constraints have been removed from the Reliability Model as this condition is considered to be outside of Hydro's established transmission planning criteria. Following the in-service of the LIL, it is expected that these constraints would only be applicable during a bipole outage at which point Hydro has

[43] "Amended and Restated Energy and Capacity Agreement," Nalcor Energy and Emera Inc., July 31, 2014.

proposed to implement emergency operating parameters as presented in "TP-TN-068 - Application of Emergency Transmission Planning Criteria for a LIL Bipole Outage," filed with the Board on July 31, 2019.

As part of the 2019 Update, system loss equations and station service load requirements were revised based on recent analysis by Hydro's Transmission Planning Department. For further details on transmission modelling, please refer to the 2018 Filing Volume I, section 4.2.5.

5.2.8 Emergency Operating Procedures - Proposed Emergency Transmission Limits

Resources are dispatched by the Newfoundland and Labrador System Operator ("NLSO") in accordance with "Operations Standard Instruction BA-P-012 (T-001) Operating Reserves," which outlines the requirements to assess and maintain sufficient operating reserve to meet current and anticipated customer needs under normal operating conditions and for specific contingency situations that result in reductions to resources.

In the event of a developing or sudden capacity shortage, the NLSO follows a number of possible mitigating actions determined based on the system conditions at the time. While some of the associated actions can provide some system relief (e.g., the implementation of voltage reduction), from a long-term planning perspective Hydro has conservatively not included the associated capacity benefits explicitly in its Reliability Model.

6.0 Modelling Results

6.1 Probabilistic Capacity Planning Results

The loss of load expectation and resultant planning reserve margin results are presented in Table 2. The results include the LOLE that has been used to determine the planning reserve margin. Planning reserve margin results have been updated to include the impact of increased operational requirements in the LOLE assessment, as discussed in section 4.2.1. This has resulted in no required change to provincial criterion and a 2% increase to the proposed planning reserve margin for the Island Interconnected System.

To ensure that capacity and energy requirements are met on the Labrador Interconnected System, that system's requirements are compared with the 300 MW block of Recapture power and associated energy and the 225 MW block of TwinCo power, all available from CF(L)Co. to ensure sufficient supply.

Table 2: Planning Reserve Margin Results

	Newfoundland and Labrador Interconnected System	Island Interconnected System
LOLE	0.1	0.1
Planning Reserve Margin (%)	13%	16%

6.2 Operational Reserve Requirements Results

As detailed in section 4.2.2, Table 3 presents operational reserves required to be available in accordance with NPCC criteria.

Table 3: Operational Reserve Requirements Results

	Operational Reserve Required (MW)
10-Minute Reserves	197.5
30-Minute Reserves	99
Total	**296.5**

As noted in Volume I, section 4.2.2.3 of the 2018 Filing, the assessment of the firm plant output of MFGS will continue to be analyzed as the plant becomes operational. If it is determined that the plant is proven capable of rated output (i.e., 824 MW) through the winter the operational reserve requirements will increase from 296.5 MW to 309 MW.

6.3 Reserve Margin Adopted

Both the probabilistic and deterministic criteria must be met. As such, Hydro recommends adoption of the probabilistic capacity criteria presented in Table 4. Additionally, Hydro recommends that the resultant reserve margin be sufficient to meet the operational reserve requirements previously presented in Table 3.

Table 4: Planning Reserve Margin Recommended Criteria

	Newfoundland and Labrador Interconnected System	Island Interconnected System
LOLE (days/year)	0.1	0.1
Planning Reserve Margin (%)	13%	16%

6.4 Comparison to Other Utilities

Figure 4 presents a comparison of the proposed planning reserve margin to those used by other Canadian regions and/or utilities. The proposed planning reserve margin is higher than those used by Manitoba Hydro, the BC region, and Sask Power, and on par with that used by Québec. While the proposed planning reserve margin is lower than that used in the Maritimes, the Maritimes have a varied supply mix with a larger penetration of thermal generation. Note that utilities with mainly hydro resources tend to use lower reserve margins, as the hydraulic assets generally experience lower forced outages than thermal assets.

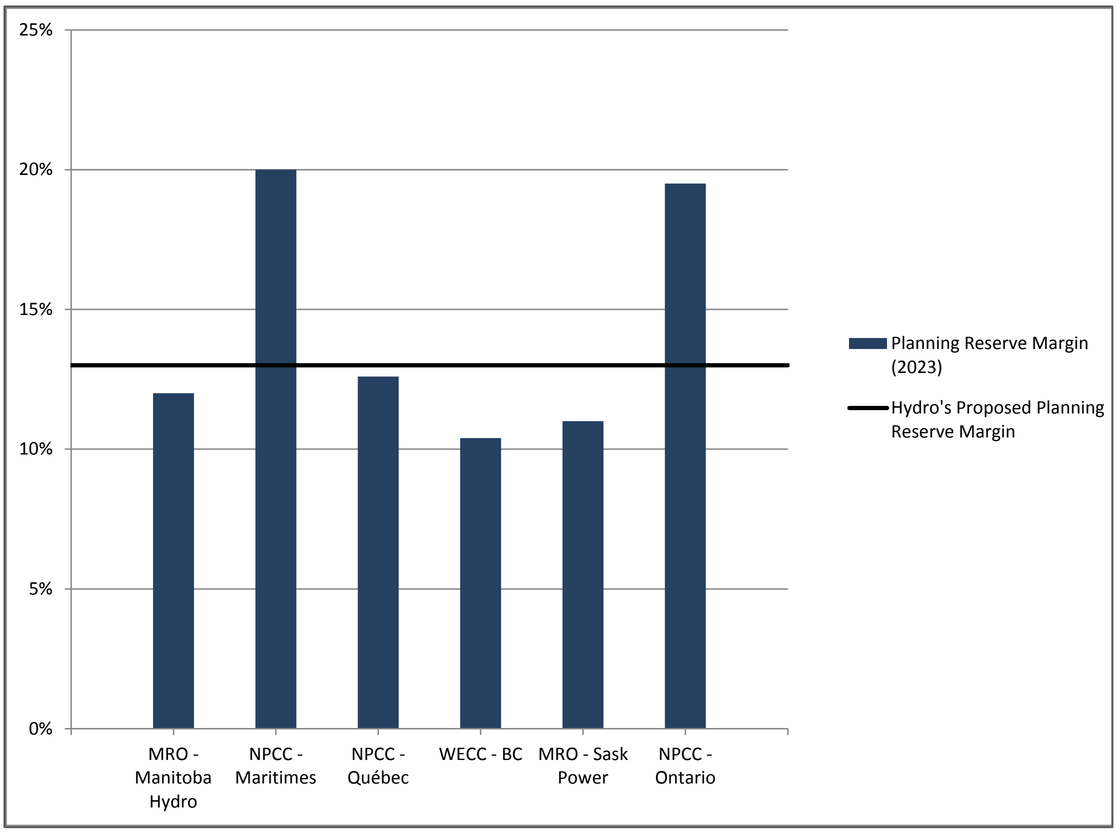


Figure 4: Proposed Planning Reserve Margin Compared to Other Canadian Jurisdictions

6.4.1 Liberty's Review and Recommendations

Liberty's Review noted that Hydro has correctly concluded that lower hydro FORs support lower reserve margins. However, Liberty's Review further noted that the comparatively small size and location of Hydro's system still may not permit it to produce on an economically sustainable basis the level of reliability that larger, more interconnected systems can enjoy, as was implicit in Hydro's earlier reliability criteria. This discussion led to Recommendation #5 of Liberty's Review:

Liberty's Recommendation #5:

"Hydro should promptly analyze whether differences in its system and those of Manitoba Hydro and Hydro Quebec have any implications for benchmarking its planning reserve margin."[44]

Assessment of Reserve Margins Used in Other Jurisdictions

In its 2018 Filing, Hydro included a comparison of its planning reserve margin to those of other Canadian utilities for illustrative purposes. As implied by Liberty in its review, comparison of reserve margins used across utilities is challenging, as each system differs in terms of load profile, resource and asset mix, number of interconnections, time line constraints, among other factors. The intent of Hydro's original statement was not to equate its reserve margin to those employed by other utilities, but rather to provide the reliability metrics employed across Canada for the information of the Board and parties. In addition, through the above statement, Hydro's intent was to offer preliminary observations on potential reasons for the differences in reserve margin observed. Hydro agrees that differences in its system as compared to those of Manitoba Hydro and Hydro Québec may merit differences in planning reserve margin. However, Hydro maintains that its proposed planning reserve margin has been developed through detailed modelling and analysis of the Newfoundland and Labrador Interconnected System, making it appropriate for use in this jurisdiction.

7.0 Conclusion

A comprehensive set of results and supporting analysis from Hydro's resource planning exercises was previously filed with the Board as part of the 2018 Filing. That analysis proposed changes to resource planning criteria stemming from the system changes as a result of interconnection. Proposed changes included:

- The migration to planning on a regional and sub-regional basis;

[44] "Review of Newfoundland and Labrador Hydro's Reliability and Resource Adequacy Study," on August 20, 2019, The Liberty Consulting Group, August 19, 2019 at p. 23.

- The migration to adoption of the LOLE target of 0.1;

The 2019 Update is filed as a complement to Hydro's 2018 Filing. It is intended to provide additional detail on matters Hydro has continued to investigate through 2019, responses to findings and recommendations made by Liberty in its review.

In terms of methodology and planning criteria, Hydro continues to recommend the following:

- ***Planning for the Newfoundland and Labrador Interconnected System on a regional and sub-regional basis;***
- ***Continuing evaluation of supply adequacy both probabilistically and deterministically;***
- ***Adoption of a system reserve margin that satisfies LOLE ≤ 0.1 for the Newfoundland and Labrador Interconnected System;***
- ***Adoption of a system reserve margin that satisfies LOLE ≤ 0.1 for the Island Interconnected System;***
- ***Maintaining sufficient operating reserve to align with NPCC operational reserve requirements; and***
- ***Extending pre-existing Island Interconnected System energy criteria to the Newfoundland and Labrador Interconnected System.***

Analysis of Effective Wind Capacity

November 15, 2019

A report to the Board of Commissioners of Public Utilities

Executive Summary

In 2018, Newfoundland and Labrador Hydro ("Hydro") expanded its analysis of the contribution of wind generation to the reliability of its system to consider the effective contribution of wind generation to meet peak demand from a planning perspective.[1] This preliminary work was expanded through 2019 following conversations with The Liberty Consulting Group ("Liberty") and additional industry analysis conducted internally. In 2019, Hydro expanded its study with two discrete areas of focus:

1) To determine the effective capacity of the existing wind generation facilities on the Island Interconnected System; and
2) To estimate the capacity of new wind generation when considered as a resource option.

In its expanded analysis, Hydro conducted an Effective Load Carrying Capability ("ELCC") study, a Cumulative Frequency Analysis ("CFA"), and considered the impact of external factors including:

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

In its 2009 Special Report, the North American Electric Reliability Corporation ("NERC") noted that the intermittent nature of the wind resource makes the determination of its capacity contribution inherently complex.

> The calculation of the capacity contribution of conventional generating units to reserve margins is somewhat straightforward, based on the unit performance rating, forced outage rate, and annual unforced maintenance cycle. However, the capacity contribution of variable generation is not intuitive due to its inherent characteristics of variability and uncertainty.[2]

[1] "Reliability and Resource Adequacy Study," Newfoundland and Labrador Hydro, September 6, 2019 (rev. 2), originally filed November 16, 2018, vol. I, s 4.2.3.1 at p.36.
[2] "Accommodating High Levels of Variable Generation," North American Electric Reliability Corporation, April 2009, at p. 38. <https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/Special%20Report%20-%20Accommodating%20High%20Levels%20of%20Variable%20Generation.pdf#search=Accommodating%20High%20Levels%20of%20Variable%20Generation>

Combining this analysis with a study of the approaches used in other jurisdictions, Hydro proposes to maintain the capacity contribution of existing and incremental wind generation sources at 22%. This level of contribution is relatively stable over a variety of assumptions.

Contents

1.0 Introduction

As part of its resource adequacy assessments, Hydro compares its available resources with its established planning criteria. Hydro can then identify requirements for additional resources and the least-cost resource plan, while ensuring sufficient system reliability. This is achieved within Hydro's modelling processes by establishing a planning reserve margin and determining when incremental resources are required such that the established reserve margin is met for the peak loads forecast in future years. Conventional generation is dispatchable, which means it can be used on demand, so it is assumed to be available at its rated capacity at the time of system peak. Non-dispatchable resources, including wind generation, cannot be assumed to be fully available on demand, making it necessary to analyze the probability that the non-dispatchable resource will provide capacity at the time of system peak.

2.0 Approach and Considerations

There are two approaches commonly observed across industry to assess the effective capacity of non-dispatchable generation: 1) ELCC and 2) CFA (commonly referred to as peak-period analysis). While both methodologies are used in industry, differences between system characteristics make it important to consider external factors specific to the jurisdiction in determining a final capacity to be attributed to wind generation. Factors considered in Hydro's analysis include:

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

The following sections provide additional detail on each of these factors, as well as the results of the ELCC and CFA analysis.

2.1 Geographical Coincidence

Wind generation at any site is primarily a function of the wind speed at the turbine. Wind speed is a function of local weather patterns and is influenced by the movement of weather systems. As such, geographic distance between sites generally increases the diversity of the wind generation, which in turn increases the contribution of those units to system reliability.

2.1.1 Existing Sites on the Island Interconnected System

The two existing wind generation sites on the Island Interconnected System are located in St. Lawrence on the Burin Peninsula and in Fermeuse on the Avalon Peninsula. There is approximately 180 km between these facilities "as the crow flies." Given the relative closeness of the two sites, it is likely they will experience similar weather patterns.

A correlation analysis was done to determine the degree of correlation between generation at the two sites. The values of correlation range from -1 to +1, with -1 indicating a perfectly negatively correlated data set, +1 indicating a perfectly positively correlated data set, and 0 indicating no correlation between the data. The analysis compared each site's total generation in each hour for the period from 2010 to 2018. The analysis was also completed with the dataset offset by up to +/- 8 hours account for the effect of the movement of weather systems.

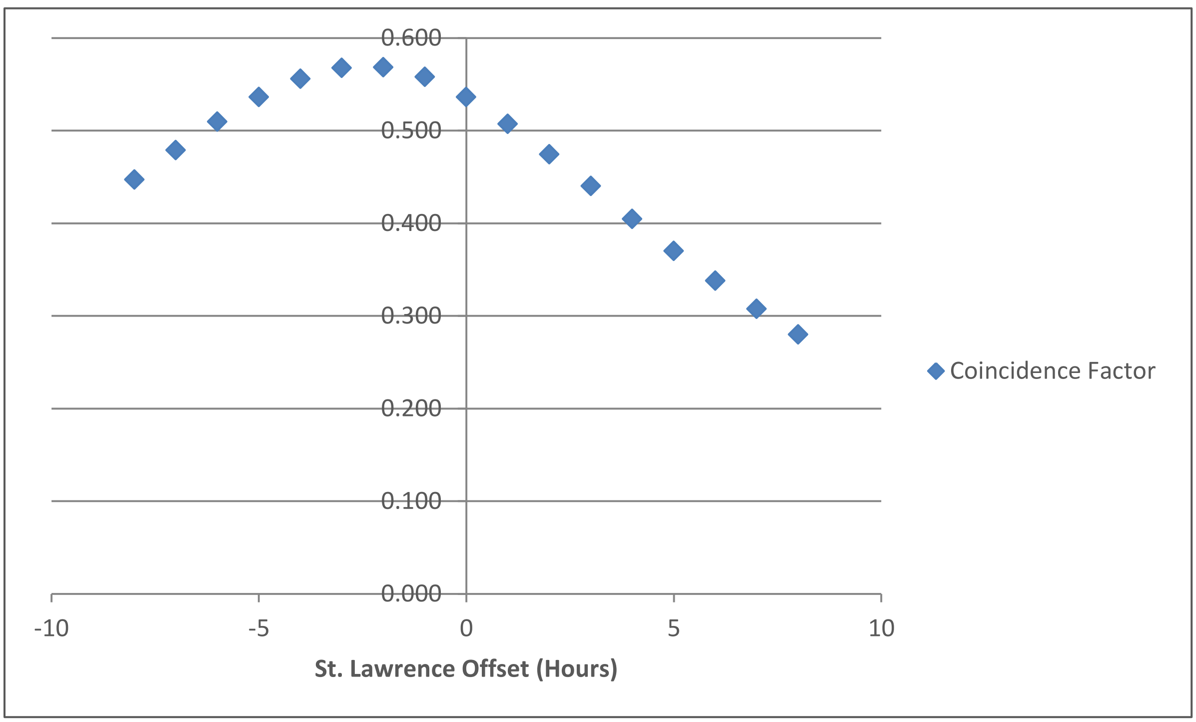


Figure 1: Coincidence vs. Hourly Offset for St. Lawrence and Fermeuse Wind Generation Facilities

Based on the analysis, the coincidence factor between the two locations is 0.536, which indicates a weak positive correlation between the data sets. When incorporating the time offset the peak coincidence is 0.568, slightly higher than the non-offset value but still fairly weakly correlated. The peak occurs at a time offset between -2 and -3 hours, which is consistent with the west-east movement of weather systems.

2.1.2 Wind as an Incremental Resource Option

The analysis of production from existing sites demonstrates that geographic separation provides diversity between generation resources, both in terms of differences in weather conditions and the time that it takes for weather systems to move between sites. It would be expected that the greater the distance between two wind generation facilities, the more weakly correlated the generation at those two sites will be. From a reliability perspective, two sites with a weak correlation provide higher contribution to system reliability than two sites with highly correlated production.

Many additional factors must be considered when selecting a site for wind generation including land availability, proximity to transmission lines, local weather conditions and distance from load centers. Because the location of new wind generation is not known, the coincidence between the existing wind generation and a potential wind expansion option is unable to be known in advance. Further, given the effective capacity of a new wind resource is a function of its coincidence with existing generation, it is not possible to determine an effective capacity that would apply to all possible wind expansion. Finally, the penetration of wind as a resource in the generation mix is important when assessing the incremental capacity associated with incremental wind generation. As increasing wind generation facilities are added to a system, achieving geographical diversity from other wind generation sources can become more challenging, resulting in diminishing returns on the incremental capacity contributed at time of system peak from the incremental resource. This phenomenon is termed saturation. The preceding factors make it appropriate to be conservative in the choice of an effective capacity to apply when considering additional wind generation as a resource candidate.

2.2 Seasonal Variation in Generation

When examining the data from the existing sites it can be seen that there is a moderate seasonal variability in the generation. As seen in Figure 2 the generation is higher in the winter months and lower in the summer months. This variation is well matched to the winter-peaking nature of the Island Interconnected System as it means there is likely to be higher wind generation during the period when system load and risk of generation shortfalls are highest.

This is incorporated in the modelling in the form of a seasonal generation profile. A separate profile is used for the winter months (December to March) and non-winter months (April to November).

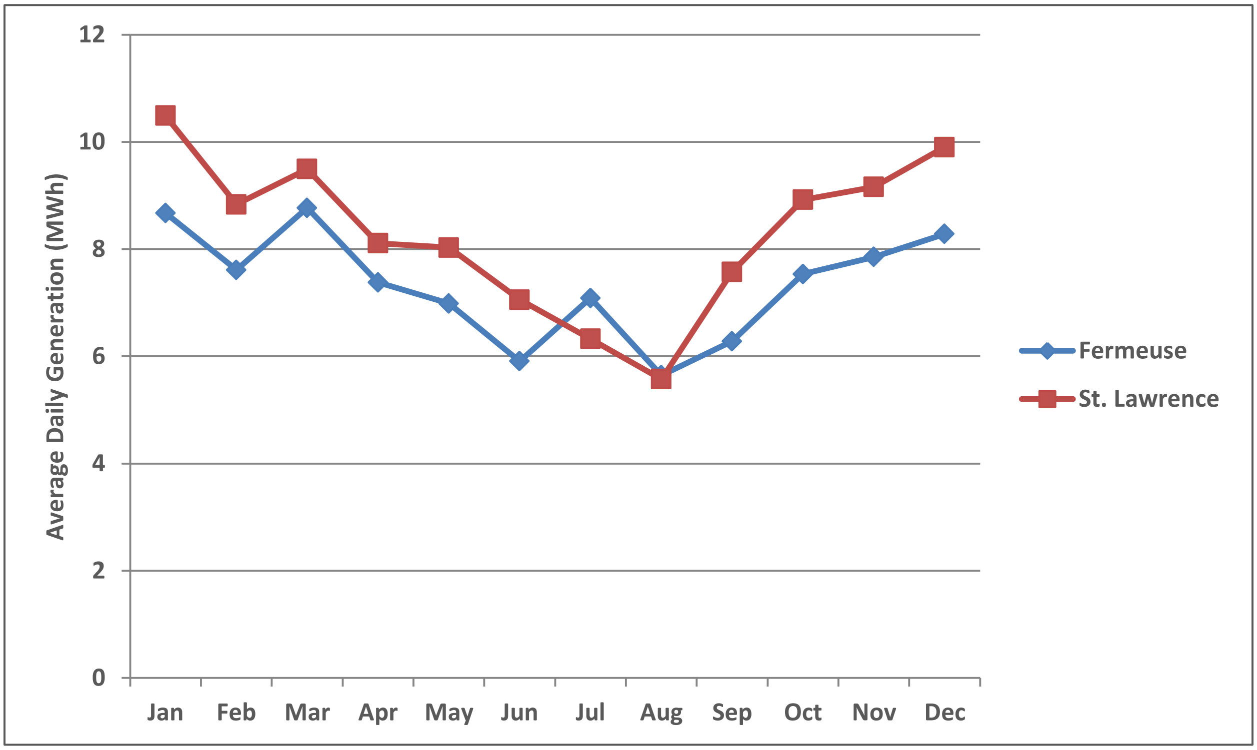


Figure 2: Average Daily Generation by Month for Existing Wind Facilities

2.3 Hourly Variation in Generation

The data from the existing sites was examined to determine if there was an observable daily pattern in the generation. It was observed that there are minor variations in the generation depending on the hour of the day.

When compared to the hours in which loss of load typically occurs it was observed that wind generation is below average during the morning peak and above average during the evening peak. Given the relatively small hourly variation in generation (i.e., a maximum variation of +/- 4 MW observed), the effect of the hourly variation does not need to be explicitly considered in the model.

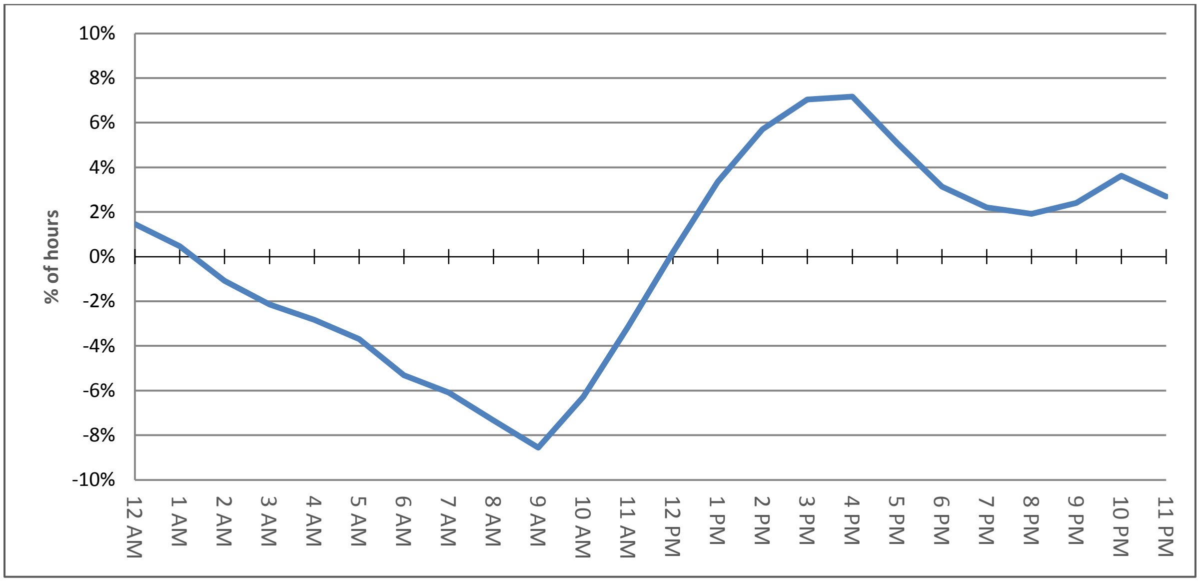


Figure 3: Percentage of Hourly Wind Generation Compared to Average

3.0 Industry Analysis

The inherent differences between jurisdictions make it important to be cautious when conducting benchmarking analysis. While a particular system may be observed to attribute more capacity to wind generation than another system, the given system's wind penetration, load profile, and seasonality are just a few factors which must be considered when comparing the two systems. Benchmarking does, however, provide an opportunity to consider the types of analysis, external factors considered, and subsequent results produced in other jurisdictions.

Across North America, both ELCC and CFA capacity approaches are applied. Most large-scale balancing authorities including PJM, Midcontinent Independent System Operator ("MISO"), California Independent System Operator ("CAISO"), and ISO New England ("ISO-NE") perform an ELCC study as the basis of determining the capacity offered by wind in the jurisdiction.[3,4,5,6]

[3] Falin, T. "Effective Load Carrying Capability (ELCC) Analysis for Wind and Solar Resources," PJM, January 10, 2019 <https://www.pjm.com/-/media/committees-groups/committees/pc/20190110/20190110-item-14a-elcc-analysis.ashx>
[4] "Planning Year 2019-2020 Wind & Solar Capacity Credit," MISO, January 18, 2019 (revision), originally filed December 10, 2018. <https://cdn.misoenergy.org/2019%20Wind%20and%20Solar%20Capacity%20Credit%20Report303063.pdf>
[5] "Deliverability Assessment Methodology," California ISO, April 24, 2019. http://www.caiso.com/Documents/IssuePaper-GenerationDeliverabilityAssessment.pdf

CFA was found to be the basis of analysis performed by Nova Scotia Power, the IESO, and the Southwest Power Pool. [7,8,9]

The Nova Scotia system has a relatively high penetration of wind. In 2015, Nova Scotia Power determined that the ELCC approach was overvaluing wind capacity in the jurisdiction, providing an effective capacity of 27%. It was observed that Nova Scotia experiences a bimodal distribution of its wind generation, meaning that while high generation could be observed at time of peak it was also likely that low generation could be observed at time of peak. Data analysis determined that in 1/3 of peak hours wind generation was less than 10% of its nameplate capacity. Calculations done using the CFA methodology resulted in a value of 12%, reduced from the 27%.[10] In its 2018 analysis, Nova Scotia Power valued the capacity contribution of wind at 17%.[11]

In some cases, assigning capacity at the annual level may not effectively capture the seasonal variability of the wind resource in a jurisdiction. For example, the Independent Electrical System Operator ("IESO"), Ontario's system operator, uses CFA and assigns different values to wind capacity in the summer and in the winter.[12] In other cases, even the seasonal approach may be insufficient as in California where, for 2019, the CAISO assigned wind capacities for each month of the year with values ranging from 8.4% to 47.5%.[13]

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[6] "New England Wind Integration Study," GE Energy Applications and Systems Engineering, EnerNex Corporation, and AWS TruePower, December 5, 2010. <https://www.iso-ne.com/static-assets/documents/committees/comm_wkgrps/prtcpnts_comm/pac/reports/2010/newis_report.pdf>
[7] "Capacity Value of Wind Assumptions and Planning Reserve Margin," Nova Scotia Power, April 23, 2014. <https://www.nspower.ca/site/media/Parent/20140423%20Wind%20Capacity%20Value%20Assumptions.pdf>
[8] "Wind and Solar Report," Southwest Power Pool, May 23, 2017. <https://www.spp.org/documents/53721/sawg%20approved_wind%20and%20solar%20report.pdf>
[9] "Methodology to Perform Long Term Assessments," Independent Electricity System Operator, September 20, 2018. <http://www.ieso.ca/-/media/files/ieso/document-library/planning-forecasts/18-month-outlook/methodology_rtaa_2018sep.pdf>
[10] "Capacity Value of Wind Assumptions and Planning Reserve Margin," Nova Scotia Power, April 23, 2014. <https://www.nspower.ca/site/media/Parent/20140423%20Wind%20Capacity%20Value%20Assumptions.pdf>
[11] "2019 Ten Year System Outlook," Nova Scotia Power, July 2, 2019. <https://www.nspower.ca/docs/default-source/pdf-to-upload/2019-10-year-system-outlook.pdf?sfvrsn=8510d516_0>
[12] "Methodology to Perform Long Term Assessments," Independent Electricity System Operator, September 20, 2018. <http://www.ieso.ca/-/media/files/ieso/document-library/planning-forecasts/18-month-outlook/methodology_rtaa_2018sep.pdf>
[13] "Deliverability Assessment Methodology," California ISO, April 24, 2019. <http://www.caiso.com/Documents/IssuePaper-GenerationDeliverabilityAssessment.pdf>

Determining capacity can be further complicated by the types of turbines. The New York Independent System Operators ("NYISO") applies different capacity values for onshore and offshore turbines and for different seasons.

Manitoba Hydro applies a seasonal capacity factor to its wind generation, attributing zero capacity to wind generation facilities at time of system peak. This is determined to be appropriate for that jurisdiction based on operational experience and the design characteristics of the wind turbines, many of which cut-out at temperatures below -30°C, which corresponds to when Manitoba Hydro is likely to experience high system demand.[14]

BC Hydro uses ELCC and applies an aggregated 26% capacity value to their combination onshore and offshore wind. Prior to 2013, it attributed to 21% and 29% to onshore and offshore respectively[15] Hydro-Québec uses ELCC and applies a 30% capacity value to the approximately 3,900 MW of wind in their system.[16,17]

Given the wide range of factors and approaches used in industry, the major observation is that a system-specific approach informed by the results of ELCC or CFA is most appropriate, with careful consideration given to external conditions that influence wind generation in the jurisdiction.

4.0 ELCC Analysis

4.1 Concept of ELCC

In 2018, Hydro conducted a preliminary assessment of the ELCC of its existing wind resources. In this approach, a quantitative analysis is undertaken to determine a percentage value that represents the

[14] "Needs For and Alternatives To Appendix 7.4 - Capacity Value of Wind Resources," Manitoba Hydro, August 2013. <http://www.pubmanitoba.ca/v1/nfat/pdf/hydro_application/appendix_07_4_capacity_value_of_wind_resources.pdf>

[15] "Integrated Resource Plan Appendix 3C – Technical Planning Assumptions: Intermittent Resources Effective Load Carrying Capability & Firm Energy Load Carrying Capability," BC Hydro, August 2013. <https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/integrated-resource-plans/current-plan/irp-appx-3c-20130802.pdf>

[16] "Northeast Power Coordinating Council Reliability Assessment for Winter 2019-19," Northeast Power Coordinating Council Inc., December 4, 2018. <https://www.npcc.org/Library/Seasonal%20Assessment/NPCC_Reliability_Assessment_for_2018-19_Winter.pdf>

[17] "2017 Long-Term Reliability Assessment," North American Electric Reliability Corporation, March 1, 2018. <https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_12132017_Final.pdf>

effect of the intermittent resource in question on system reliability through comparison to an ideal dispatchable generator. Hydro continued to refine its approach to ELCC through 2019.

ELCC should be calculated based on individual generating sites or on groupings of sites of similar characteristics (e.g., type, location, size, capacity factor, etc.). For the purpose of this study, an ELCC will be calculated for the combined wind farms at St. Lawrence and Fermeuse.

In general, the ELCC of a unit is a function of how much generation capacity is available during peak or near peak hours. This is a function of the correlation between the generation and the provincial electrical demand, both on an hourly and seasonal level, as well as the capacity factor of the unit. For example, the ELCC of solar energy is near zero in Newfoundland because:

- The seasonal correlation is low: solar output is much higher in summer months, when demand is low;
- The hourly coincidence is low: solar output very low or zero during the morning and evening peaks in the winter; and
- The overall capacity factor of solar energy is low because of local weather conditions.

For the purposes of this study, the two wind farms on this island are considered as a single unit and the ELCC is calculated based on the combined generation. This is appropriate given the similarities between the two sites:

- Both sites have the same installed capacity: Each site has an installed capacity of 27 MW.
- Both sites are comprised of the same number of units of the same model turbine: Each site has nine 3 MW Vestas V90 turbines.
- The sites are geographically close to each other; and
- The sites have similar capacity factors: For the period 2010-2018, the average capacity factor for the Fermeuse site was 38%, while the capacity factor for the St. Lawrence site was generally 43%.

The ELCC of the wind farms are also examined on the basis of the two wind farms operating independently to further understand the effect of the coincidence between the two wind farms.

In the study the existing wind generation is compared to an existing ideal generator. The ideal generator is assumed to have no forced outage rate, no energy limitations and is available at full capacity in any hour. Since the ELCC is used as an input to the resource adequacy process, the concept of an ideal generator is used to avoid the implicit comparison to a specific expansion resource option.

4.2 Modelling

Hydro's ELCC study was completed using the PLEXOS model. The historical hourly wind generation data from January 2010 to June 2018 for both the Fermeuse and St. Lawrence Wind Farms was analyzed, resulting in a probability distribution for the wind generation in percentage by MW. The distribution was further separated into Winter (December to March) and Non-Winter (April to November) to more accurately determine the effect of the wind generation in the winter months where loss of load is more likely to occur given the winter peaking nature of the Island Interconnected System.[18] The distribution was then modelled in PLEXOS as a probability distribution representing each respective wind farm during the summer and winter periods. Refer to Figure 4 to Figure 7 for the winter and non-winter generation profiles of each wind farm and the combined profile.

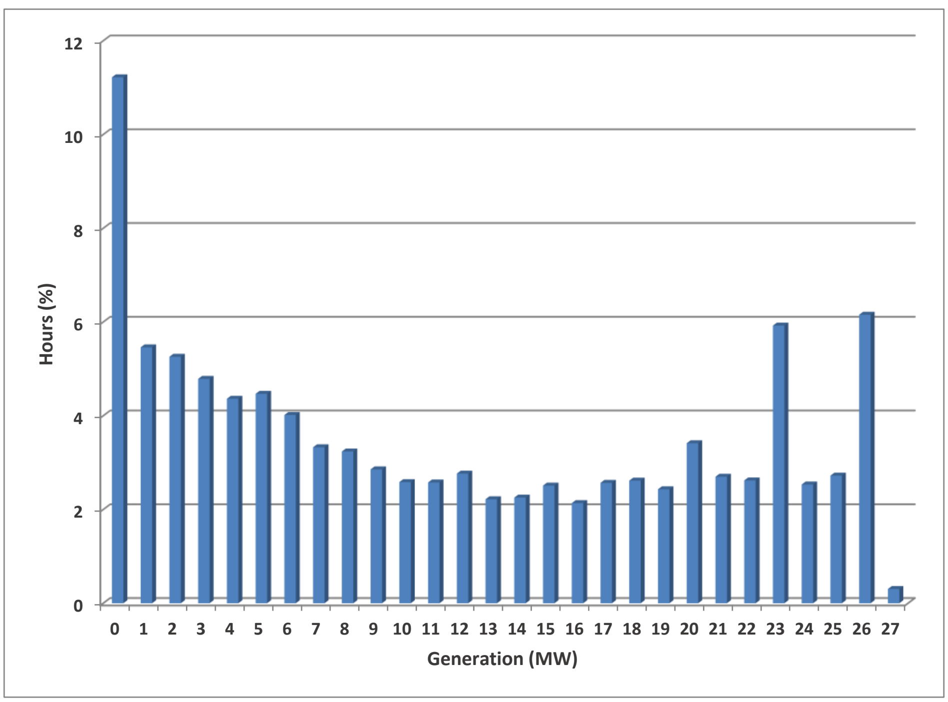

Figure 4: Fermeuse Generation from December to March (2010–2018)

[18] Likelihood of loss of load is calculated in PLEXOS using the loss of load hours ("LOLH") parameter.

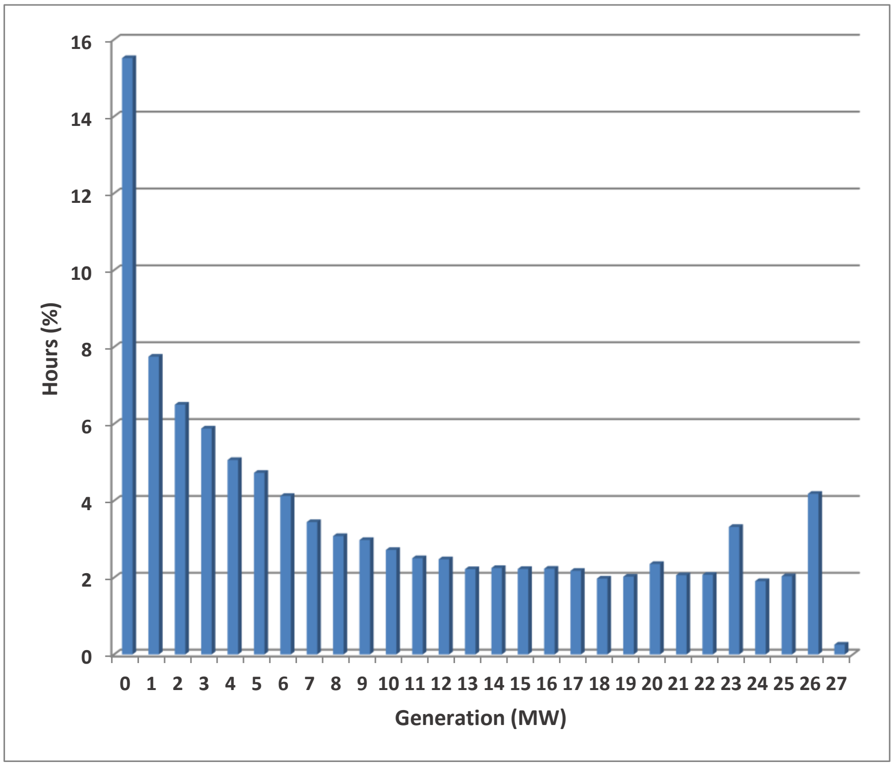

Figure 5: Fermeuse Generation from April to November (2010–2018)

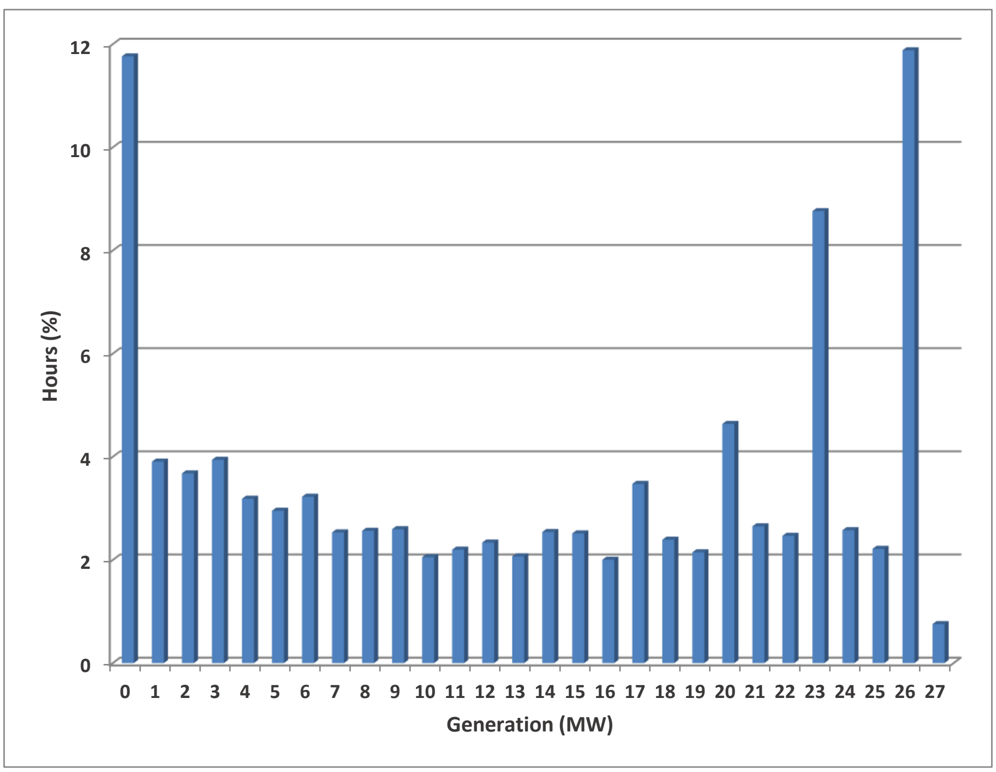

Figure 6: St. Lawrence Generation from December to March (2010–2018)

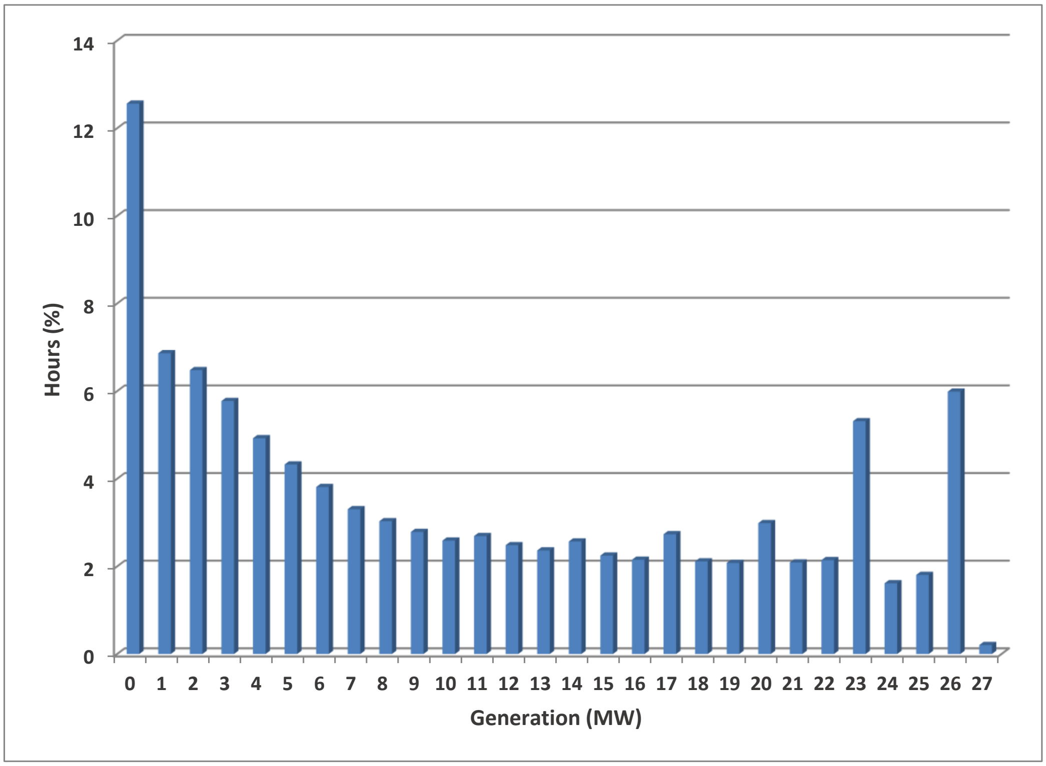

Figure 7: St. Lawrence Generation from April to November (2010–2018)

4.3 Methodology

The methodology used in the ELCC study is generally as follows:

1) The reliability model is run for the test year, 2026, to determine the resultant system Loss of Load Hours ("LOLH"). This is the baseline model.

2) The load in the test year is scaled using a constant load factor until the LOLH is equal to approximately 0.62.[19]

3) The run is repeated with 48,000 samples to minimize the statistical variation in the results.

4) The wind generators are removed from the model and the model is returned to the baseline model.

5) An ideal generator is added to the model.

[19] Hydro's current assumptions and modelling of the test year indicate that a loss of load expectation ("LOLE") of 0.1 is approximately equivalent to LOLH of 0.62.

6) The capacity of the ideal generator is adjusted and the model is run until the LOLH simulation results from the model are equal to those obtained in Step 2 using the wind generators.
7) The run is repeated with 48,000 samples
8) The ELCC of the wind generators is then determined to be equivalent to the capacity of the ideal generator in this simulation.

The process above was executed in varying configurations to ensure appropriate understanding of the behavior of the existing wind production facilities on the Island Interconnected System and appropriate understanding of how additional facilities constructed on the Island Interconnected System could impact results. Configurations 1 and 2 are meant to increase understanding of the impact of facilities already in production on the Island Interconnected System, while configurations 3 and 4 are meant to quantify the impact of additional wind generation on the ELCC of wind generation on the Island Interconnected System.

- Configuration 1: St. Lawrence and Fermeuse modelled as distinct facilities with independent generation;
- Configuration 2: St. Lawrence and Fermeuse modelled as a joint facility with a combined profile;
- Configuration 3: St. Lawrence and Fermeuse modelled as a joint facility with a combined profile with one additional perfectly correlated 54 MW wind farm;
- Configuration 4: St. Lawrence and Fermeuse modelled as a joint facility with a combined profile with one additional uncorrelated 54 MW wind farm

Configuration 3 assumes that the additional wind farm would be perfectly correlated with existing generation and would represent a doubling of the size of the two existing wind farms. Configuration 4 assumes that the expansion wind farm would be uncorrelated with existing generation and would represent a wind farm built a large distance away from the existing wind farms. These cases are considered to provide the theoretical minimum and maximum ELCC of an expansion of equal size to that of the existing wind generation on the Island Interconnected System.

4.4 Results

The results of the ELCC analysis from PLEXOS are given in Table 1.

Table 1: Results of Hydro's ELCC Analysis

	Configuration	Description	Capacity	Percentage
Existing	1	Independent	22 MW	41%
	2	Combined	18 MW	33%
Expansion	3	Perfectly Correlated	3 MW[20]	6%
	4	No correlation	17 MW[21]	31%

When considered on a completely independent basis, the ELCC of the two existing wind farms is 22 MW or 41%, based on a rated capacity of 54 MW. However, when the two wind farms were considered on a combined basis, reflecting the true coincidence of the two generators, the ELCC was 18 MW or 33%. This decrease reflects the correlation between the two existing sites.

When extended to consider expansion wind generation, the analysis produced a wide range of possible values for capacity. Configuration 3, representing a wind farm perfectly correlated with the existing wind farms, produced an ELCC of 21 MW. This is an increase of 3 MW over Configuration 2 which implies that the ELCC of the new wind farm would be approximately 6%. Configuration 4, representing an expansion wind farm with similar characteristics to the existing wind farms but completely uncorrelated, resulted in an ELCC of 35 MW. This implies that in this case the ELCC of the expansion wind farm would be 17 MW or 31%.

Results of the analysis indicate that correlation of the wind resource is a key factor in determining the effective capacity of a wind farm. The capacity provided by a new wind farm would be somewhere between the 6% of the perfectly correlated wind farm and the 31% of an uncorrelated wind farm.

5.0 Cumulative Frequency Analysis

5.1 Methodology

The distribution curves observed in Figure 1 through Figure 4 demonstrate that observed wind generation in the current system is not normally distributed. CFA provides a method to account for the non-normal distribution of data by using historical data to determine lower bounds for generation

[20] This is the extra total wind capacity provided by the addition of one wind farm of similar size to the existing two.
[21] This is the extra total wind capacity provided by the addition of one wind farm of similar size to the existing two.

during peak hours. Some form of this approach is used by many utilities and system operators including Nova Scotia Power, Southwest Power Pool, the NYISO, and the IESO.[22,23,24,25]

The methodology used in Hydro's CFA is as follows:

- Gather hourly data for wind generation and system load for the period from 2010 to 2018.
- For each year, look at wind generation during the top 10% of system load hours.
- Create cumulative frequency distribution to determine the likelihood of wind generation exceeding a certain value

5.2 Results

Hydro performed the CFA following the methodology outline above, using the combined wind generation for the Fermeuse and St. Lawrence farms and comparing it with the total Island demand. The results of this analysis are shown in Table 2. To assist with data interpretation, 95% confidence means that during 95% of peak hours the combined production of the Fermeuse and St. Lawrence wind farms was a minimum of least 1 MW.[26]

Table 2: Results of Hydro's Cumulative Frequency Analysis

Confidence	Capacity	Capacity
95%	1.0 MW	2%
90%	3.5 MW	6%
85%	6.0 MW	11%
80%	9.0 MW	17%
75%	11.5 MW	21%

[22] "Capacity Value of Wind Assumptions and Planning Reserve Margins," Nova Scotia Power, April 23, 2014. <https://www.nspower.ca/site/media/Parent/20140423%20Wind%20Capacity%20Value%20Assumptions.pdf>

[23] "Wind and Solar Report," Southwest Power Pool, May 23, 2017. <https://www.spp.org/documents/53721/sawg%20approved_wind%20and%20solar%20report.pdf>

[24] "Methodology to Perform Long Term Assessments," Independent Electricity System Operator, September 20, 2018. <http://www.ieso.ca/-/media/files/ieso/document-library/planning-forecasts/18-month-outlook/methodology_rtaa_2018sep.pdf>

[25] Smith, Z.T. "Capacity Value Summary," New York Independent System Operator, December 18, 2018. <https://www.nyiso.com/documents/20142/4020230/Capacity+Value+Study+Summary+1218.pdf/02ae9793-44cb-0fb3-c08d-9ee63e69baa6?version=1.1&download=true>

[26] In this instance, peak hours refers to hours with the top 10% demand from 2010 to 2018.

85% confidence is most commonly used in industry for wind capacity, including SPP and NSP.[27] In this case, the two wind farms on the Island would have a combined effective capacity of 11%, or 6 MW.

6.0 Comparison of Methodologies and Conclusion

The two objectives of this analysis were to:

1) Determine the effective capacity of the existing wind generation facilities on the Island Interconnected System; and
2) Estimate the capacity of new wind generation when considered as a resource option.

6.1 Existing Wind Generation Sources

The ELCC analysis showed the combined percentage for the existing wind farms to be 31%, applied uniformly across the year and throughout the day. The considered factors show variation, but not to the extent that results would be materially different in their impact on system reliability.

The CFA results indicated a more conservative 11% contribution for the existing wind farms based on 85% confidence.

Hydro's current value of 22% is between the results generated using the two methodologies. Table 3 provides a summary of the result of each measure and effective MW value for the current system.

Table 3: Results of Analysis

Measure	Result	MW
ELCC	31%	18
CFA	11%	6
Hydro's Current Approach	22%	12

Given that the current value of 22% is between results provided using the ELCC and CFA methods, it could be considered to provide a balanced approach. Further, given that the difference in MW is relatively small between the different approaches and Hydro's current assumption (+/- 6 MW), Hydro considers the use of 22% to be appropriately conservative by reducing the risk associated with

[27] "Capacity Value of Wind Assumptions and Planning Reserve Margins," Nova Scotia Power, April 23, 2014. <https://www.nspower.ca/site/media/Parent/20140423%20Wind%20Capacity%20Value%20Assumptions.pdf>

overvaluing the contribution of wind as a resource, while recognizing that wind can contribute capacity to the system, with real-time changes in wind generation covered by Hydro's operating reserve

6.2 New Wind Generation as a Resource Option

Hydro proposes to continue to study the impact of wind generation on its system and the contribution of the same to system reliability in the future, if wind is expected to play a significant role in system expansion.

Reliability and Resource Adequacy Study
2019 Update
Volume II: Near-Term Reliability Report

November 15, 2019

A report to the Board of Commissioners of Public Utilities

Contents

1.0 Introduction

Newfoundland and Labrador Hydro ("Hydro") recognizes that supply adequacy in advance of the availability of full production from the Muskrat Falls Generating Station ("MFGS") is top of mind for its stakeholders. The enclosed assessment of near-term resource adequacy takes an in-depth view of system risks and mitigating measures to ensure Hydro can reliably meet the needs of its customers through the full system transition.

This volume of the 2019 Update to the Reliability and Resource Adequacy Study ("2019 Update") discusses the near-term resource adequacy and reliability of the Newfoundland and Labrador Interconnected System for the study period, a 5-year horizon from 2020–2024, and provides the results of the probabilistic resource adequacy assessment for the Newfoundland and Labrador Interconnected System for the study period. The reliability indices in this near-term report include both annual and monthly Loss of Load Hours ("LOLH"), Expected Unserved Energy ("EUE"), and Normalized EUE[1] for a five-year period. The analysis considers the different types of generating units (i.e., thermal, hydro, and wind) in Hydro's fleet, firm capacity contractual sales and purchases, transmission constraints, peak load, load variations, load forecast uncertainty, and demand side management programs. Similar to previous analyses, a range of projected availabilities was considered for the Holyrood Thermal Generating Station ("Holyrood TGS").

The analysis was conducted consistent with the format proposed in the North American Electric Reliability Corporation ("NERC") "Probabilistic Assessment Technical Guideline Document" that provides modelling "*practices, requirements and recommendations needed to perform high-quality probabilistic resource adequacy assessments.*"[2] As such, this edition of the near-term report is similar in structure to prior near-term generation filings, paired with the assessment guidelines as defined by NERC.

The *"*Probabilistic Assessment Technical Guideline Document" suggests a more granular view of resource adequacy, focusing on monthly and annual LOLH and EUE reporting. By conducting this type of analysis, the impact of system changes can more easily be observed than by using an annual analysis only. As LOLH and EUE do not currently have generally acceptable criterion, unlike the generally

[1] Normalized EUE provides a measure relative to the size of the assessment area. It is defined as: [(Expected Unserved Energy)/(Net Energy for Load)] x 1,000,000 with the measure of per unit parts per million.
[2] "Probabilistic Assessment Technical Guideline Document," North American Electric Reliability Corporation, August 2016. <https://www.nerc.com/comm/PC/PAITF/ProbA%20Technical%20Guideline%20Document%20-%20Final.pdf>

accepted LOLE criterion of 0.1, the quantified results are presented to show how loss of load changes based on system conditions rather than for comparison against a threshold.

> ***The granular near-term view provides insight into the impact of seasonal load and generation variations on supply events. This can be used to further inform decisions on the most appropriate resource options as system requirements evolve, resulting in more informed long-term planning.***

Given the current evolving nature of the Newfoundland and Labrador Interconnected System, an analysis was conducted for each of the next five years (2020–2024) to provide the Board of Commissioners of Public Utilities ("Board") with insight into the evolution of system reliability as the Muskrat Falls project assets are reliably integrated into the Newfoundland and Labrador Interconnected System. Further to the Board's request in correspondence dated October 22, 2019, Hydro has also modelled the resultant system reliability if the Labrador-Island Link ("LIL") remained unavailable through 2023, with varying levels of availability of the Holyrood TGS.

The analysis in the 2019 Update has been completed using Hydro's reliability model. This is the same model that supported Hydro's "Near-Term Generation Adequacy Report," filed in May 15, 2019, and Hydro's "2019–2020 Winter Readiness Planning Report," filed October 10, 2019, with updates to reflect current system assumptions. A detailed discussion of the modelling approach used can be found in Volumes I and II of the Reliability and Resource Adequacy Study, filed in November 2018 ("2018 Filing"). A discussion of changes to the model from the 2018 Filing can be found in Volume I of the 2019 Update.

2.0 Consideration of Liberty's Review and Recommendations

Throughout 2019, The Liberty Consulting Group ("Liberty") conducted a thorough review of Hydro's 2018 Filing. The review consisted of initial documentation review, on-site interviews, and independent analysis. While Liberty's "Review of Newfoundland and Labrador Hydro's Reliability and Resource Adequacy Study," filed with the Board August 19, 2019 ("Liberty's Review") proposed a number of recommendations, generally Liberty was supportive of much of the work Hydro completed, stating:

> ***"While we recommend testing and validation, and adjustment if thereby warranted, of some methods and criteria, none of our recommendations undercut the value of using the current analysis as a foundation for examining supply reliability risks, consequences, and solutions."*[3]**

Hydro has reviewed Liberty's Report and Table 1 highlights each recommendation and the location of Hydro's response within the 2019 Update. Table 1 is located at the beginning of each volume of the 2019 Update for ease of reference. Rows with bold text indicate that Hydro's response to Liberty's recommendations can be found in that particular volume of the 2019 Update.

Table 1: Location of Responses to Liberty's Recommendations

Item	Recommendation	Location in the 2019 Update
Study Methods, Assumptions, and Criteria		
1a	Hydro should promptly examine the likelihood and the range of consequences of an extended bipole LIL outage under extreme weather circumstances,	Vol. III, s 7.2.1
1b	and should undertake a robust examination of generation options (including continued use of the Holyrood steam units) to mitigate that risk.	Vol. III, s 5.6.1
2	Hydro should promptly commence a stakeholder engagement process to address Value of Loss Load ("VOLL"), informed by a sound contemporaneous examination of extended bipole outage risk and the options, including extension of generation at Holyrood, for mitigating that risk.	Vol. III, s 3.1
3	Hydro should continue to reflect both P50 and P90 weather conditions as part of its efforts to assess system reliability and economy as it acquires more information in the coming months.	Vol. I, s 4.2.4
4	Hydro should verify that its means for addressing the relationship between planning and operating reserve margins does not introduce significant error.	Vol. I, s 4.2.1
5	Hydro should promptly analyze whether differences in its system and those of Manitoba Hydro and Hydro Quebec have any implications for benchmarking its planning reserve margin.	Vol. I, s 6.5.1
Long-Term Reliability		
6	Hydro should establish a plan and schedule for integrating the results of the current examination and subsequent processes for considering factors affecting future electrical requirements and non-generation means for influencing load and usage into a re-analysis of its future needs under a	Executive Summary

[3] "Review of Newfoundland and Labrador Hydro's Reliability and Resource Adequacy Study," The Liberty Consulting Group, August 19, 2019 at p. 17.

Item	Recommendation	Location in the 2019 Update
	robust range of circumstances and scenarios.	
7	Promptly conduct the analyses necessary to assess short-term and indefinite extension of Holyrood's life as a supply reserve.	Vol. III, s 4.1.1
Near-Term Reliability		
8	**Immediately conduct a detailed assessment of the impacts of a delay in LIL operation into and past the coming winter.**	**Vol. II, s 4.2.1**
9	Resolving the issues that have surrounded LIL monopole availability should continue to form a critical focus and Hydro should ensure that longer-term uncertainties about Holyrood's future do not lead to decisions that compromise its ability to operate reliably now.	Vol. III, s 4.1.1
Extended LIL Outages		
10	Hydro should conduct a detailed analysis quantifying the probabilities and restoration durations for a robust range of bipole LIL outages.	Vol. III, s 7.2.1
11	Hydro should complete remaining steps to prepare for LIL outages as soon as possible.	Vol. III, s 7.2.1
Generation Asset Reliability		
12	Engage an entity with substantial experience in boiler construction and repair to conduct a detailed assessment of Holyrood's major systems.	Vol. III, s 5.6.1

With respect to recommendation #13, Hydro appreciates Liberty's suggestions for further enhancements to its asset management processes. Hydro is considering items noted by Liberty for inclusion in its asset maintenance program.

3.0 Modelling Approach

Hydro completed detailed modelling of the near-term supply period using the reliability model developed in 2018 and updated with the current system assumptions.[4] Transmission system adequacy is assessed separately in accordance with Transmission Planning Criteria; these are posted publically on the Newfoundland and Labrador System Operator ("NLSO") Open Access Same-Time Information System ("OASIS") website.[5]

[4] For a detailed description of the modelling parameters and assumptions, refer to Volume I, Section 4.2 of the 2018 Filing.
[5] NLSO Standard Transmission Planning Criteria Doc # TP-S-007," Newfoundland and Labrador Hydro, May 11, 2018. <http://www.oasis.oati.com/woa/docs/NLSO/NLSOdocs/TP-S-007_Transmission_Planning_Criteria_UPDATED_ 05112018.pdf>

4.0 Asset Reliability

On a quarterly basis, Hydro reports to the Board including actual forced outage rates and their relation to:

- the rolling 12-month performance of its units,[6]
- past historical rates; and
- assumptions used in assessment of resource adequacy.

The most recent report was submitted on October 31, 2019, for the quarter ending September 30, 2019. These reports detail unit reliability issues experienced in the previous 12-month period and compare performance for the same period year-over-year.

Hydro continues to take actions to address repeat performance issues by conducting broader reviews which frequently involve external experts, addressing issues with urgency, and placing an increased focus on asset reliability.

These actions are intended to support reliable unit operation and increase the likelihood of improved reliability in near-term operating seasons.

4.1 Factors Affecting Recent Historical Generating Asset Reliability

Hydro has reviewed the factors affecting generating unit reliability since its "Near-Term Generation Adequacy Report." Updates on these items, as well as any additional items which may impact asset performance in the near-term, are provided in this volume of the 2019 Update. The intention is to ensure issues affecting reliability have been appropriately addressed as issues that are recurring in nature, can have a significant impact on unit reliability if not managed properly. The information included in sections 4.1.1 through 4.1.3 of the 2019 Update provide an overview of the repeat or broader issues. Isolated equipment issues (i.e., those that occur once on a particular unit) are also investigated, with the root cause identified and corrected. These types of issues are reflected in the calculation of Derated Adjusted Forced Outage Rates ("DAFOR") and Derated Adjusted Utilization Forced Outage Probabilities ("DAUFOP").

[6] Quarterly Report on Performance of Generating Units.

The following sections provide a description of issues, both asset- and condition-based, that have previously affected generating unit reliability, as well as the current status of those issues and the actions taken to mitigate against future reliability impacts. The scope is not limited to Hydro's assets (e.g., penstock, boiler tubes), but also considers environmental challenges facing Hydro's operations (e.g., lower than average inflows). As part of this exercise, Hydro has identified the following items, grouped by facility type:

- **Hydraulic Facilities**: Continued monitoring (Bay d'Espoir Penstocks and Upper Salmon rotor rim key cracking); and ongoing (Hinds Lake rotor resistance, Granite Canal control system);
- **Thermal Facilities**: Ongoing (unit boiler tubes, and variable frequency drives); and resolved (air flow limitations due to normal boiler fouling during operating season, and Unit 1 and Unit 2 hydraulic fluid condition); and
- **Gas Turbines**: Resolved (Exciter Vibration at Hardwoods).

Any factors that impact unit availability, including those that have historically contributed to unit outages, are reflected in the DAFOR and DAUFOP assumptions selected for each asset.

4.1.1 Hydraulic

Bay d'Espoir Penstocks

In 2018, Hydro conducted condition assessments of Bay d'Espoir Penstocks 1, 2, and 3, which included the completion of three reports prepared by a third-party consultant. These reports have been completed, reviewed, and the final report was filed with the Board in July 2019. On September 22, 2019, Hydro experienced a failure of Penstock 1 which resulted in a forced outage to Bay d'Espoir Units 1 and 2.

In response to previous penstock failures, as part of an ongoing effort to monitor the performance of the penstocks and ensure reliability in the short-term, Hydro implemented an annual internal inspection program for Penstocks 1 to 3 in Bay d'Espoir. The 2019 annual inspections of Penstocks 2 and 3 were completed during the maintenance season and did not identify any major defects or areas of concern. The inspection of Penstock 1 had been scheduled for October 2019. Following the failure on September 22, 2019, the inspection of Penstock 1 was advanced and completed while the penstock was undergoing repairs. The results of the 2019 inspection revealed no major defects or areas of concern outside of the ruptured zone.

Although the inspection did not reveal any immediate concerns Hydro recognizes that Penstock 1 is nearing the end of life. To mitigate potential impacts should another leak in Penstock 1 occur, Hydro has taken proactive measures to ensure reduced downtime. These actions include having an inventory of long lead time materials available (e.g., rolled steel plate), ensuring availability of welding resources, and engagement of an additional engineering consultant to ensure development of an appropriate long-term plan. Hydro has also implemented an operating regime for Units 1 and 2 at Bay d'Espoir to limit rough zone operation for Penstock 1. In this operating regime, once dispatched, Units 1 and 2 are limited to a minimum unit loading of 50 MW and are not cycled or shut down as part of normal system operations.

Hinds Lake Rotor Resistance

As noted in the "Near-Term Generation Adequacy Report" resistance readings from the Hinds Lake rotor are measured during annual maintenance inspections. These have trended down over the past several years, approaching the critical level of 0.14 Mohms as established by the Original Equipment Manufacturer ("OEM").

The Hinds Lake unit was removed from service on August 18, 2019 for a planned outage to complete the required rewind of the rotor poles. The unit is expected to return to service following the completion of its 2019 maintenance program in late November. It is expected that the rotor resistance issue will be considered resolved at that time.

Granite Canal Control System

In the "Near-Term Generation Adequacy Report" Hydro noted that it had planned a thorough engineering assessment of the system in response to control system malfunctions experienced when remotely starting and/or stopping the Granite Canal unit. This assessment has been completed. Modifications to equipment, as well as minor logical changes were implemented and additional findings have been compiled and are currently under review by the OEM and Hydro Engineering Services. Following the conclusion of the review by the OEM and Hydro Engineering Services, any additional modifications will be assessed and implemented. Hydro will propose any required capital work, as per its established capital budget process.

Upper Salmon Rotor Key Cracking

In 2018, Hydro replaced the rotor rim keys during the unit annual maintenance outage at Upper Salmon. As per consultation with the OEM, Hydro has continued to schedule and conduct regular inspections of the new rotor rim keys at Upper Salmon and will continue to monitor this situation throughout the anticipated wear-in period of the new keys and assess the effectiveness of the replacement keys. The 2019 annual maintenance outage at Upper Salmon was completed in October 2019, including a thorough review of the keys installed in 2018 continued cracking was discovered. At the time, the decision was made to continue regularly scheduled inspections through the winter operating season.

4.1.2 Thermal

Unit Boiler Tubes

Each of the three thermal generating units at the Holyrood TGS has a boiler that contains tubes. Boiler tube failures are a common issue in thermal power plants due to the inherent design, which requires relatively thin walls for heat transfer that are subjected to high temperatures and stresses. Hydro inspects boiler tubes on an annual basis to verify the condition and to identify trends.

To mitigate the possibility of tube failures, Hydro conducts an annual tube inspection program, most recently completed during the 2019 annual outages. Hydro has determined that boiler tube sections, as a whole, are in good condition. Hydro continues to recognize that tube failures pose a risk, particularly given the age of the Holyrood boilers. Hydro maintains a thorough selection of spare tube material and has an established contract with Babcock & Wilcox for the provision of emergency repairs in the event of tube failures. As such, should a tube failure occur, the expected return to service time is accounted for in the projected DAFOR targets.

Variable Frequency Drives

Forced draft fans provide combustion air required for boiler operation at the Holyrood TGS. The Variable Frequency Drives (“VFD”) were installed to more efficiently vary the amount of air required based on generation need. This reduces auxiliary power requirements and results in fuel savings.

Hydro completed preventive maintenance work on the drives in 2018 and ensured appropriate spares were available. For the 2018–2019 operating season, Hydro also implemented operating strategies to reduce the likelihood of VFD failures, such as pre-energizing VFD equipment prior to unit start-ups.

There was one VFD related failure during the 2018–2019 operating season when a power cell failed on the Holyrood TGS Unit 2 in October of 2018, causing a forced derating to 70 MW for approximately eight hours.

Hydro has recently been experiencing issues with power cell failure when the drives are re-energized after an extended shut down. Hydro completed preventive maintenance on the drives with Siemens in 2019 and found that eight power cells had faults when they were re-energized during the outage as part of the Preventative Maintenance ("PM") program. Two additional cells faulted on each unit when the Holyrood TGS Units 2 and 3 were returned to service, and one faulted during the return to service of Holyrood TGS Unit 1. Note that there are 12 power cells per drive and two drives per unit for a total of 72 cells across three units. Hydro is working with Siemens to resolve these re-energization issues. Failed cells were sent to Siemens for evaluation and refurbishment. Seven have been returned to site while the other five are being serviced by Siemens. These five cells will be returned to site prior to the Winter Readiness date of December 1, 2019. Hydro has also placed an order for an additional six spare cells to increase the level of spare cells from nine to fifteen. These additional spare cells are expected on site prior to the end of 2019. Hydro anticipates that the frequency of cell failures will be low once all units are back on line for the winter.

In October 2019 there were two fan failures, one on each of Holyrood TGS Units 1 and 2. While the two failures do not appear to be related, it appears that one or both may have been related to the VFDs. All faults have been cleared and the units returned to service. Investigation is ongoing with assistance from the VFD OEM.

Air Flow Limitations

Appropriate air flow is required to provide enough air for combustion to enable units to provide full output. Prior to the 2018–2019 operating season, all three units had deratings due to insufficient air flow caused by fouling of the air heaters and boiler sections, including the economizer, and from air heater leakage due to normal wear and tear.

During the 2018 annual outage season, Hydro was successful in eliminating these deratings by chemically washing the Holyrood TGS Unit 1 and Unit 2 economizers, and by replacing air heater baskets in all three units. For the 2018–2019 operating season, Hydro was able to operate all three units at full load capability. Unit capabilities were successfully tested and confirmed throughout the operating season. Capabilities were maintained through effective sootblower operation, maintenance of the Magnesium Oxide (“MgO”) fuel additive system and burner guns, air heater washes, and control of operational parameters.

As a precaution, to avoid possible deratings during the 2019–2020 operating season, a chemical wash of the economizers and the air heaters was completed during the 2019 annual outages. All three units have returned to service with full load capability for the 2019–2020 operating season.

Liberty’s Review noted that, with respect to the air flow limitations, “Hydro has resolved these issues with specific actions”[7] and “Combustion air systems issues should not significantly impair unit reliability in the immediate term.”[8]

To minimize and control fouling going forward, Hydro has maintained all sootblowers and burners during the 2019 annual outages and will continue to use MgO fuel additive. Performance throughout 2019-2020 will be monitored and if fouling indicates a need for intervention during the 2020 outages, the same will be planned as appropriate. Hydro considers this issue to be resolved.

Holyrood TGS Unit 1 and Unit 2 Hydraulic Fluid Condition

In the first quarter of 2018, Hydro observed contamination in the hydraulic fluid that is used to operate the Holyrood TGS Unit 1 and Unit 2 turbine valves.[9] The level of fluid contamination observed required fluid and filter replacement. As a mitigating measure, flushing was completed during the 2018 annual outages for both units to replace the fluid and clean the systems. However, continued hydraulic contamination issues caused a forced outage on the Holyrood TGS Unit 1 in November of 2018. This prompted additional and extensive work on both the Holyrood TGS Units 1 and 2 in November and December. To support this work, Hydro engaged a technical field representative from the OEM, GE, as well as local hydraulics contractor, Pennecon.

[7] “Review of Newfoundland and Labrador Hydro’s Reliability and Resource Adequacy Study," The Liberty Consulting Group, August 19, 2019 at p. 56.
[8] “Review of Newfoundland and Labrador Hydro’s Reliability and Resource Adequacy Study," The Liberty Consulting Group, August 19, 2019 at p. 56.
[9] Contamination had been observed through regular sampling. On March 22, 2018, the contamination resulted in a forced outage on the Holyrood TGS Unit 2. On April 3, 2018, the Holyrood TGS Unit 2 was taken off-line for repair of the hydraulic ram for the turbine control valves.

After completion of this work, there were no further operational issues related to the hydraulic fluid condition. Hydro continued to perform weekly fluid sample analyses during the 2018–2019 winter operating season and all results were acceptable.

To support continued reliable operation, additional work was completed during the 2019 annual outages for the Holyrood TGS Units 1 and 2. Additional new equipment was installed including air dryers and filter carts that will further enhance the fluid condition. Further, a technical representative from GE came to site to demonstrate the disassembly procedure for the dump valves and all necessary spare parts to refurbish these dump valves have now been added to inventory. Hydro is confident in the condition of the dump valves and has the ability to quickly correct any issues that might arise in the future.

Hydro will continue to monitor the systems through monthly fluid samples during the 2019–2020 operating season. Hydro considers this issue to be resolved.

4.1.3 Gas Turbines

Exciter Bearing Vibration at Hardwoods

The Hardwoods Gas Turbine ("Hardwoods GT") was derated to 25 MW following a unit trip on February 21, 2019, while placing End B in service. The trip occurred as a result of high exciter bearing vibration, which occurred only when End B was being placed online. The alternator and exciter OEM, Brush, was engaged to complete a non-intrusive inspection of the bearing to determine whether End B could be returned to service immediately or would require replacement of bearing components. This inspection was completed the week of May 20, 2019. The inspection found wear on the journal and thrust bearings and also found that the clearances were not within acceptable tolerances. Hydro installed its spare journal bearing and polished the existing thrust pads successfully returning End B to service. Hydro considers this issue to be resolved.

4.2 Near Term Assumptions for the Lower Churchill Project Assets

In correspondence with the Board dated August 8, 2019, Hydro provided an update regarding the progress of the commissioning activities associated with the LIL. In this correspondence, Hydro indicated that the LIL would be undergoing dynamic commissioning from mid-October 2019 to mid-February 2020 and would be out of service for an additional period from mid-April to mid-May 2020. This would result in the LIL being unavailable for the majority of the winter period.

4.2.1 Liberty's Review and Recommendations

In its review of Hydro's assessment of Near-term Reliability, Liberty correctly noted that both the LIL and Holyrood performance are significant to system reliability in the near-term.[10] Based on that assessment, Liberty recommended better understanding of the impacts of delay in the LIL for the coming winter season.

Liberty's Recommendation #8:

"Immediately conduct a detailed assessment of the impacts of a delay in LIL operation into and past the coming winter."

Hydro completed this analysis for the 2019–2020 winter operating season, and included the results and discussion of its analysis as part of its Winter Readiness assessment filed with the Board October 10, 2019.[11]

Following receipt of Hydro's analysis, in correspondence dated October 22, 2019 the Board requested additional analysis on the basis that the LIL may not be fully functional once placed in service. Specifically, the Board requested that Hydro provide the following:

> With respect to Liberty Recommendation #8 (LIL operation delays) an assessment of system reliability with respect to alternate scenarios for LIL availability, including no availability and varying Holyrood Thermal Generating Station availability in the 2021 to 2023 timeframe.

In response, Hydro has developed and modelled five scenarios which consider no availability of the LIL, varying availability at Holyrood TGS, and the availability of market purchases over the Maritime Link.[12] Additional detail on the parameters of the considered scenarios is provided in section 7.1.

[10] "Review of Newfoundland and Labrador Hydro's Reliability and Resource Adequacy Study," The Liberty Consulting Group, August 19, 2019 at p. 34.
[11] "2019–2020 Winter Readiness Planning Report," Newfoundland and Labrador Hydro, October 10, 2019.
[12] In scenarios where the LIL is modelled as unavailable through 2023, generation from the MFGS is unavailable to serve either Island Interconnected System demand or the Nova Scotia Block.

For scenarios where the LIL is modelled as available, the forced outage rate of the LIL is modelled conservatively in order to capture any testing activities and potential operational unknowns during the first years of operation.[13] Similarly, in these scenarios first generation from the MFGS is expected in 2019. Following the in-service of the first unit, the remaining three units will be placed in service through 2020. Delivery of the Nova Scotia Block[14] will commence once the third unit has been successfully commissioned and the in-service of the LIL enables the energy to be delivered.

4.3 Selection of Appropriate Performance Ratings

4.3.1 Consideration of Asset Reliability in System Planning

Hydro's asset reliability is a critical component in determining its ability to meet planning criteria for the Newfoundland and Labrador Interconnected System. As an input to the assessment of resource adequacy, unit forced outage rates ("FOR") provide a measure of the expected level of availability due to unforeseen circumstances.[15]

The forced outage rate methodology applied in the 2018 Filing and the 2019 Update varied by asset class, ownership, and condition. Appropriate FORs were determined based on historical data, where available, or the most recent industry average. The FOR is calculated using different metrics depending on the primary operating mode of the units. For units that primarily operate on a continuous basis, specifically units at Holyrood TGS and hydroelectric units, the FOR is based on the historical DAFOR. For units that primarily operate as peaking units, specifically gas turbine units, the FOR is based on the historical DAUFOP. Analysis was performed for a range of Holyrood TGS DAFOR assumptions to provide an indication of the sensitivity of supply adequacy to changes in Holyrood TGS availability. For units not owned by Hydro, Canadian Electricity Association ("CEA") or NERC metrics were used.

FOR assumptions are developed annually to incorporate the most recent data available. A detailed description of the development of the FOR assumptions used is found in Volume III, attachment 1 of the 2019 Update. Table 2 summarizes the projected availability of Hydro's generating assets considered in

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[13] In 2020, the monopole forced outage rate is assumed to be 10% for each pole. The forced outage rate assumption decreases to 2.5% in 2021, 1% in 2022, and finally to the long-term forced outage rate of 0.556% per pole in 2023.

[14] The Nova Scotia Block is a firm annual commitment of 980 GWh, to be supplied from the MFGS on peak.

[15] For the purposes of the 2019 Update, forced outage rate refers to an input to the reliability model, which represents the percentage of hours in a year when a unit is unavailable.

the assessment of near-term supply adequacy. These projections of asset reliability include appropriate consideration of asset availability and deration.

Table 2: Forced Outage Rates for Hydro-Owned Assets

Asset	Reliability Metric
Hydraulic Units	DAFOR = 2.8%
Holyrood Thermal Units	DAFOR = 15%, 18%, 20%
Holyrood Gas Turbine	DAUFOP = 1.7%
Happy-Valley Gas Turbine	DAUFOP = 9.8%
Stephenville Gas Turbine	DAUFOP = 30%
Hardwoods Gas Turbine	DAUFOP = 30%
Diesels	DAUFOP = 6.2%

For units not owned by Hydro, the forced outage rates used in Hydro's modelling are determined using industry averages. Updated forced outage rates used for assets owned by a third party in this analysis are presented in Table 3.

Table 3: Forced Outage Rates for Third-Party-Owned Assets

Asset	Reliability Metric
Hydraulic Units	DAFOR = 5.7%
Gas Turbines	DAUFOP = 13.6%
Corner Brook Cogen.	DAUFOP = 15.8%

4.4 Selection of Appropriate Performance Ratings

The Maritime Link is expected to be available to import energy during the 2019–2020 winter operating season. Hydro successfully imported energy over the Maritime Link through the 2018–2019 winter operating season. To date, Hydro has been focused on purchasing energy to offset higher cost thermal energy on both a short-term and longer-term basis.

While all of Hydro's market purchases to date have been made on an economic basis, Hydro has been also been successful in making market purchases that have had system reliability benefits. As an example, Hydro experienced high customer demand during the period from February 19 to 26, 2019, with a system record peak of 1,784 MW on February 20, 2019. During that period, Hydro chose to seek imports on an economic basis, as well as to increase system reliability. Energy was imported for 94% of hours during that week, with purchases fulfilled as requested in all but four hours; during two of those hours a deal was not achieved, during the other two hours a deal was achieved for a portion of the volume requested. Figure 1 shows imported quantities over the Maritime Link during that time period. In Figure 1 it can be observed that Hydro was successful in importing in excess of 125 MW for prolonged periods of time, with a maximum import of 185 MW for four hours.

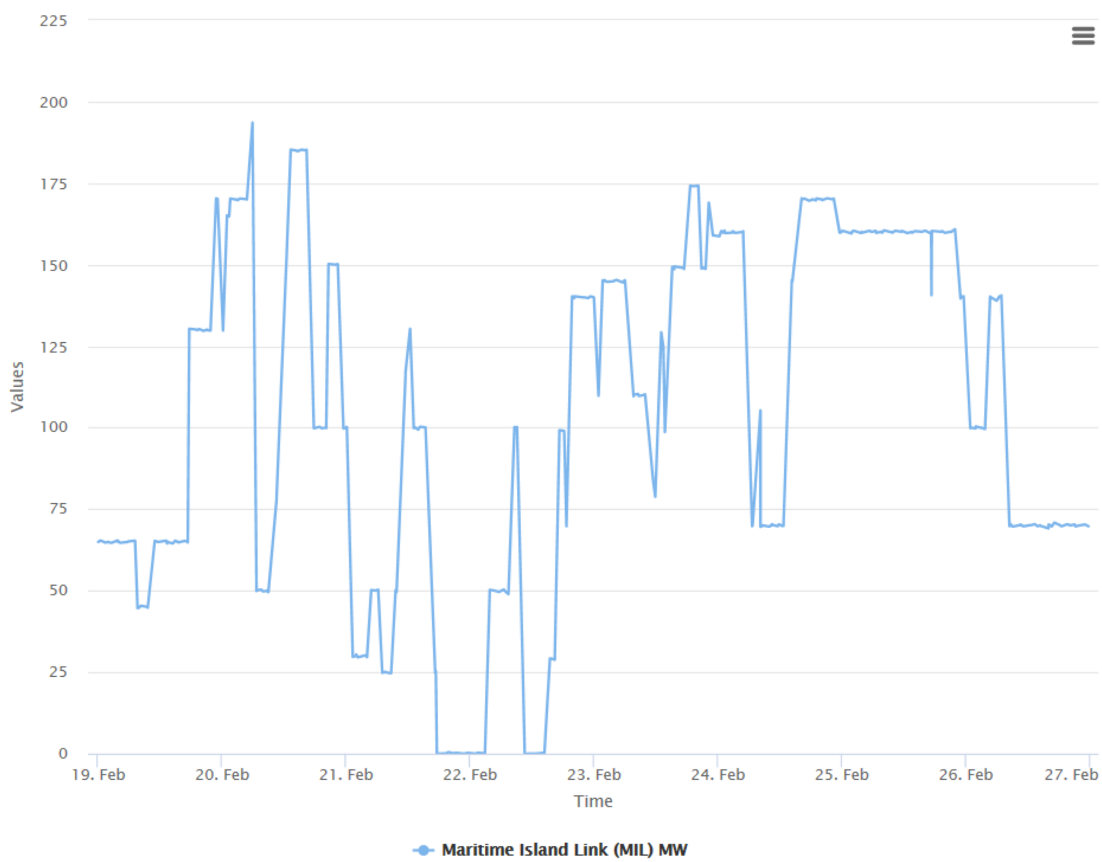

Figure 1: Imports over Maritime Link between February 19 and 26, 2019

Hydro can also purchase energy and capacity for economic reasons by doing short-term transactions or by making larger, longer term commitments. In March 2019, Nalcor Energy Marketing ("NEM") entered into a contract on Hydro's behalf for unit-firm capacity from a third-party for 100 MW on-peak and 50 MW off-peak. Based on the analysis of the data from March 2019, the contracted amount was supplied in all hours. NEM has also successfully entered into a multiple agreements on Hydro's behalf during the fall of 2019 including the purchase of 24.5 GWh of energy in October 2019, which combined with real-time opportunistic purchases resulted in total imports of 53.3 GWh in October 2019 and 60 GWh in November 2019 with a delivery profile of 100 MW on peak and 50 MW off peak.

Based on Hydro's experience with securing market purchases to date, import scenarios are contemplated as sensitivities to the expected case in this report; that is firm imports of 50 MW and 100 MW from December 2019 to March 2020 with an associated FOR intended to serve as proxy for anticipated potential interruptions to the import. Since the availability of these contracts depends on the availability of capacity from a third-party to provide firm capacity, there is no guarantee that these contracts would be available. The analysis demonstrates the effect on the system if the capacity was available in the requested amounts.

4.5 Asset Retirement Plans

4.5.1 Holyrood Thermal Generating Station

The Holyrood TGS Units 1 and 2 were commissioned in 1971 and Unit 3 was commissioned in 1979. The three units combined provide a total firm capacity of 490 MW. Based on the established schedule for power delivery from the Muskrat Falls project, the Holyrood TGS is expected to have all three units available for operation at full capacity until March 31, 2021. Beyond that date, Unit 3 at the Holyrood TGS will continue to operate as a synchronous condenser, while Units 1 and 2 are scheduled to be shut down and decommissioned.

Hydro has also worked to develop a contingency plan to extend the operation of Holyrood TGS by one to two years, if required in the event of further delays in the reliable supply of energy from the Muskrat Falls project. Additional information on this contingency plan is provided in Volume III, section 4.1.1 of the 2019 Update. By the end of 2019, Hydro will be better informed to decide whether extended operation of Holyrood TGS is required past March 31, 2021. At that time, Hydro expects to have more clarity surrounding key milestones associated with the Muskrat Falls project. In January 2020 Hydro will provide the Board with its decision regarding a short-term extension (i.e., one to two years).

4.5.2 Hardwoods and Stephenville Gas Turbines

The Stephenville Gas Turbine ("Stephenville GT") consists of two, 25 MW gas generators that were commissioned in 1975. The Hardwoods GT consists of two, 25 MW gas generators that were commissioned in 1976. Each plant provides 50 MW of firm capacity to the system. These units were designed to operate in either generation mode to meet peak and emergency power requirements or synchronous condense mode to provide voltage support to the Island Interconnected System. While Hydro had intended to retire these assets later in the 2020s, the criteria for dispatching the units materially changed in 2014, resulting in increased frequency and duration of operation. As such, there have been operational issues in recent years that have impacted the reliability of the plants and resulted in increased maintenance costs. Hydro plans to confirm retirement plans of these assets following stakeholder review of the 2018 Filing.

5.0 Load Forecast

5.1 Load Forecasting

A detailed discussion of the load forecast process and load forecast used is provided in Volume III, section 6 of the 2019 Update.

6.0 System Constraints and Future Supply Risk

To fully understand the potential supply risk posed to the Island Interconnected System, both energy and capacity analysis were conducted.

6.1 System Energy Capability

In August 2019 Hydro revised its minimum storage limits for the remainder of the year in consideration of continued delays in the availability of the LIL to deliver energy to the Island Interconnected System. System energy analysis was conducted assuming no energy deliveries to the Island Interconnected System from the LIL throughout winter 2019–2020. The results of this analysis indicated that Hydro needs to produce and/or procure additional energy to ensure its ability to reliably supply customers through the winter in the event of the critical dry sequence. This will help ensure that if the LIL continues to be delayed beyond this winter, Hydro will have sufficient storage to reliably serve its customers.

Following the revision of its minimum storage limits, Hydro engaged NEM to import energy on its behalf when available and economic. To the end of October 2019, NEM had imported 75.8 GWh, which includes an import deal of 24.5 GWh for the month of October 2019. Hydro also entered into a firm capacity and energy purchase agreement with Corner Brook Pulp and Paper Limited ("CBPP") of 13.5 GWh for two weeks in November 2019. In addition, an agreement for the import of 60 GWh is in place for the entire month of November 2019. Further mitigation efforts included the early return to service and maximization of generation at the Holyrood TGS units in the fall 2019. Units 1, 2, and 3 at the

Holyrood TGS are required to generate during the fall 2019 and winter 2019–2020 to provide capacity and the balance of energy to meet Hydro's customer and system reliability requirements.

A series of rainfall events over all reservoir basins occurred in early to mid-November 2019, increasing the total system energy in storage to 1415 GWh by November 14, 2019, above the revised minimum storage limit. At the end of October 31, 2019, the total system energy in storage was 1,186 GWh; 231 GWh below the revised minimum storage limit of 1,417 GWh for October 2019. Figure 2 plots the 2018 and 2019 storage levels, minimum storage limits, maximum operating level storage, and the 20-year average aggregate storage for comparison.

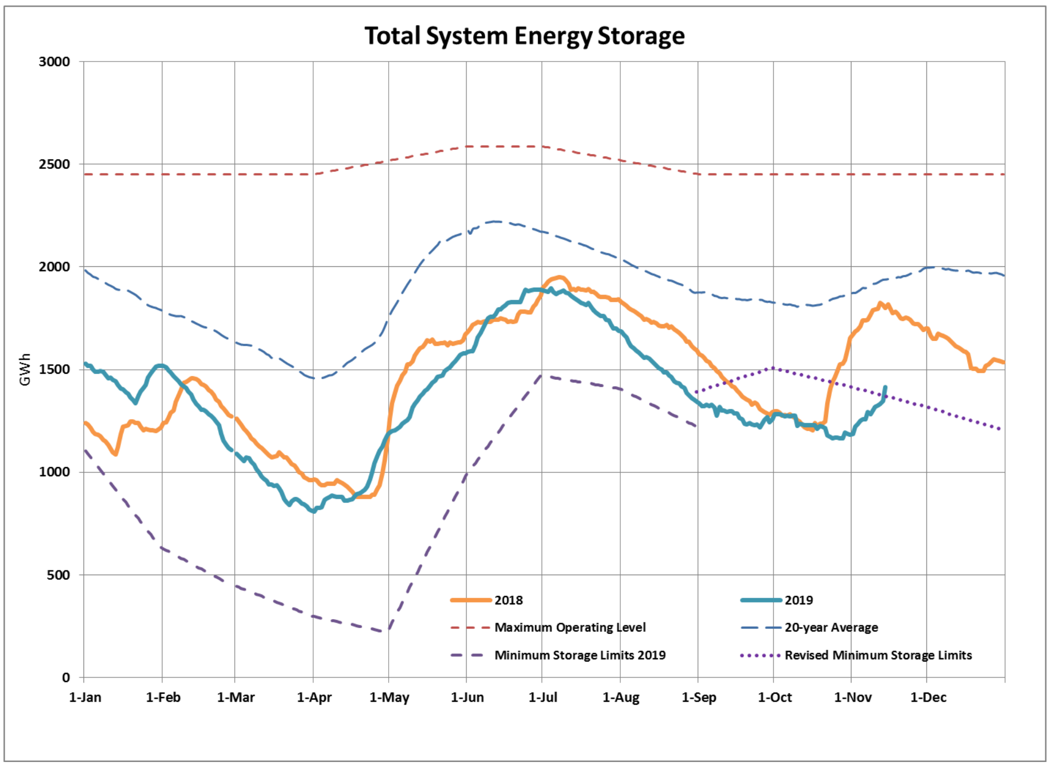

Figure 2: Total System Energy Storage for October 31, 2019

Storage in the reservoir systems is being monitored closely to minimize the risk posed to Hydro's ability to reliably supply customers. Hydro will continue to monitor the requirements for thermal energy and market imports to support reservoir levels and adjust as required. Imports will be used to supplement generation from the Holyrood TGS if energy in storage remains low, otherwise imports will be used to offset thermal generation to the extent that it is economically and technically feasible. At this point, Hydro does not foresee using production from standby generation to support reservoir levels.

7.0 Results

The following subsections provide a description of the eight scenarios considered, and the anticipated system reliability in each scenario (i.e., LOLH, EUE, and normalized EUE results).

7.1 Scenario Analysis

Eight scenarios were analyzed to assess system reliability under a range of potential system conditions:

- **Scenario 1:** The expected case, which includes no availability of the LIL prior to June 1, 2020. This case assumes a DAFOR of 15% for the Holyrood TGS and retirement of the Holyrood TGS on March 31, 2021.
- **Scenario 2:** Varies from Scenario 1 by increasing the Holyrood TGS DAFOR to 18%.
- **Scenario 3:** Varies from Scenario 1 by increasing the Holyrood TGS DAFOR to 20%.
- **Scenario 4:** Varies from Scenario 1 by considering the LIL to be out of service through 2023.
- **Scenario 5:** Varies from Scenario 4 by increasing the Holyrood TGS DAFOR to 18%.
- **Scenario 6:** Varies from Scenario 4 by increasing the Holyrood TGS DAFOR to 20%.
- **Scenario 7:** Varies from Scenario 6 by including 50 MW of imports all hours.
- **Scenario 8:** Varies from Scenario 6 by including 100 MW of imports all hours.

For Scenarios 1 to 3, it is assumed that the Holyrood TGS is retired from generation mode on March 31, 2021 following the reliable in-service of the Muskrat Falls project assets. For scenarios 4 to 8 it is assumed that the Holyrood TGS, Hardwoods GT, and Stephenville GT remain in service, the contracts for capacity assistance with CBPP and Vale Newfoundland and Labrador Limited are continued through 2023 and the delivery of the Nova Scotia Block is delayed through 2023.

7.2 Expected Unserved Energy and Loss of Load Hours Analysis

Sections 7.2.1 and 7.2.2 provide the results of the annual and monthly analysis, respectively.

7.2.1 Annual Assessment Results

Table 4 provides the annual LOLH, EUE and normalized EUE results. Note that the basis for comparison of results is Hydro's existing LOLH criterion of not more than 2.8 hours per year. Hydro's intends to migrate to its proposed criteria of 0.1 LOLE when the Muskrat Falls project has been fully commissioned and thermal generation at the Holyrood TGS, Hardwoods, and Stephenville have been retired.

Where scenarios are no longer relevant (i.e., the increase in DAFOR for the Holyrood TGS no longer varies the LOLH or EUE once the plant has been is retired), the results have been noted as not applicable ("N/A").

Table 4: Annual LOLH, EUE, and Normalized EUE Results

Reliability Metric					
LOLH (hours)	**2020**	**2021**	**2022**	**2023**	**2024**
S1: Expected Case, Holyrood TGS DAFOR = 15%	2.43	0.14	0.31	0.45	0.58
S2: Expected Case, Holyrood TGS DAFOR = 18%	3.72	0.15	N/A	N/A	N/A
S3: Expected Case, Holyrood TGS DAFOR = 20%	4.77	0.15	N/A	N/A	N/A
S4: No LIL, Holyrood TGS DAFOR = 15%	3.11	2.96	3.55	4.05	N/A
S5: No LIL, Holyrood TGS DAFOR = 18%,	4.65	4.60	5.30	6.04	N/A
S6: No LIL, Holyrood TGS DAFOR = 20%	5.95	5.84	6.81	7.75	N/A
S7: No LIL, Holyrood TGS DAFOR = 20%, 50 MW imports	3.02	3.16	3.79	4.30	N/A
S8: No LIL, Holyrood TGS DAFOR = 20%, 100 MW imports	1.57	1.78	2.11	2.46	N/A
EUE (MWh)	**2020**	**2021**	**2022**	**2023**	**2024**
S1: Expected Case, Holyrood TGS DAFOR = 15%	128	12	27	41	52
S2: Expected Case, Holyrood TGS DAFOR = 18%	199	13	N/A	N/A	N/A
S3: Expected Case, Holyrood TGS DAFOR = 20%	261	14	N/A	N/A	N/A
S4: No LIL, Holyrood TGS DAFOR = 15%	164	156	189	218	N/A
S5: No LIL, Holyrood TGS DAFOR = 18%,	253	246	288	334	N/A
S6: No LIL, Holyrood TGS DAFOR = 20%	328	324	386	440	N/A
S7: No LIL, Holyrood TGS DAFOR = 20%, 50 MW imports	156	164	199	228	N/A
S8: No LIL, Holyrood TGS DAFOR = 20%, 100 MW imports	73	87	104	124	N/A
Normalized EUE (ppm)	**2020**	**2021**	**2022**	**2023**	**2024**
S1: Expected Case, Holyrood TGS DAFOR = 15%	11.8	1.1	2.5	3.7	4.7
S2: Expected Case, Holyrood TGS DAFOR = 18%	18.4	1.1	N/A	N/A	N/A
S3: Expected Case, Holyrood TGS DAFOR = 20%	24.1	1.2	N/A	N/A	N/A
S4: No LIL, Holyrood TGS DAFOR = 15%	15.1	14.1	17.1	19.8	N/A
S5: No LIL, Holyrood TGS DAFOR = 18%,	23.3	22.4	26.1	30.3	N/A
S6: No LIL, Holyrood TGS DAFOR = 20%	30.2	29.4	35.0	39.9	N/A
S7: No LIL, Holyrood TGS DAFOR = 20%, 50 MW imports	14.4	14.9	18.0	20.7	N/A
S8: No LIL, Holyrood TGS DAFOR = 20%, 100 MW imports	6.8	7.9	9.4	11.2	N/A

Higher levels of LOLH and EUE are observed in all scenarios during 2020, with both LOLH and EUE growing as the Holyrood TGS unavailability increases. In Scenarios 1 through 3 the LOLH and EUE drop significantly once the LIL is in service and grow slowly over time as the system load increases. In Scenarios 4 through 6, where the LIL remains unavailable until 2023, the EUE and LOLH remain higher for the duration of the study period. Similar to the 2020 results, both metrics increase with the Holyrood TGS unavailability. Both metrics also increase as system load increases.

Based on these results, it can be observed that there is an increased risk of generation shortfall until the LIL is in service, with the amount of risk highly dependent on the availability of the Holyrood TGS. As demonstrated in Scenarios 7 and 8, imports over the Maritime Link could be used to mitigate the risk of generation shortfall. An import of 100 MW in all hours from December to March would be sufficient to reduce the risk of generation shortfall to an acceptable level in the most onerous modelled scenario.

7.2.2 Monthly Assessment Results

Table 5 through Table 9 provide analyses of LOLH and EUE for each year by month. The monthly analyses provide additional detail that assists in examining the complexity of the changing power system that would not necessarily be apparent from an analysis of the annual results only. Completing monthly analyses allows for easier identification of changes in system behaviour. For example, if a system had a change in forecast peak demand with no resultant change in annual LOLH or EUE, the monthly analysis would indicate where differences in LOLH and EUE were anticipated, allowing for better understanding of the drivers of the annual results. This type of analysis is used by NERC-regulated utilities to complement long-term reliability assessments.

High values of LOLH and EUE are observed in all scenarios during the winter months of 2020, with both LOLH and EUE growing as the Holyrood TGS unavailability increases.

In Scenarios 1 to 3 LOLH and EUE are observed to decrease significantly as generation becomes available at the MFGS and the LIL enters normal operation, resulting in a low value of LOLH and EUE during the winter of 2020–2021 when Holyrood TGS and the LIL are both in-service. Once Holyrood TGS and the Hardwoods GT and Stephenville GT are retired, LOLH increases and continues to rise slowly as Newfoundland and Labrador Interconnected System load increases.

In Scenarios 4 to 6, the LOLH and EUE remain high and increase as the Island Interconnected System increases resulting in increased exposure in all of the scenarios, especially when the Holyrood TGS unavailability increases beyond 15%. As seen in Scenarios 7 and 8, the import of firm energy over the Maritime Link produces a significant improvement in system reliability. This demonstrates that firm imports could be used to mitigate the increased risk of resource shortfalls if the LIL is delayed or if the Holyrood TGS or other generating assets were to perform more poorly than expected.

Table 5: Monthly LOLH and EUE for 2020

LOLH (hours)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
S1: Expected Case, Holyrood TGS DAFOR = 15%	1.20	0.70	0.50	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02
S2: Expected Case, Holyrood TGS DAFOR = 18%	1.80	1.14	0.75	0.01	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.02
S3: Expected Case, Holyrood TGS DAFOR = 20%	2.34	1.41	0.97	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.03
S4: No LIL, Holyrood TGS DAFOR = 15%	1.19	0.72	0.52	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.66
S5: No LIL, Holyrood TGS DAFOR = 18%,	1.76	1.10	0.79	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.03	0.95
S6: No LIL, Holyrood TGS DAFOR = 20%	2.25	1.46	0.98	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.05	1.20
S7: No LIL, Holyrood TGS DAFOR = 20%, 50 MW imports	1.13	0.69	0.49	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.05	0.65
S8: No LIL, Holyrood TGS DAFOR = 20%, 100 MW imports	0.55	0.32	0.24	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.05	0.40

EUE (MWh)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
S1: Expected Case, Holyrood TGS DAFOR = 15%	64	36	27	0	0	0	0	0	0	0	0	1
S2: Expected Case, Holyrood TGS DAFOR = 18%	99	59	39	0	0	0	0	0	0	0	0	1
S3: Expected Case, Holyrood TGS DAFOR = 20%	130	74	54	0	0	0	0	0	0	0	0	2
S4: No LIL, Holyrood TGS DAFOR = 15%	61	38	27	0	0	0	0	0	0	0	1	37
S5: No LIL, Holyrood TGS DAFOR = 18%,	95	56	43	0	0	0	0	0	0	0	2	56
S6: No LIL, Holyrood TGS DAFOR = 20%	123	77	54	0	0	0	0	0	0	0	3	70
S7: No LIL, Holyrood TGS DAFOR = 20%, 50 MW imports	58	33	26	0	0	0	0	0	0	0	2	36
S8: No LIL, Holyrood TGS DAFOR = 20%, 100 MW imports	25	14	11	0	0	0	0	0	0	0	2	21

Table 6: Monthly LOLH and EUE for 2021

LOLH (hours)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
S1: Expected Case, Holyrood TGS DAFOR = 15%	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.12
S2: Expected Case, Holyrood TGS DAFOR = 18%	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.12
S3: Expected Case, Holyrood TGS DAFOR = 20%	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.12
S4: No LIL, Holyrood TGS DAFOR = 15%	1.06	0.74	0.50	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.63
S5: No LIL, Holyrood TGS DAFOR = 18%,	1.66	1.17	0.77	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.05	0.93
S6: No LIL, Holyrood TGS DAFOR = 20%	2.14	1.47	0.98	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.06	1.19
S7: No LIL, Holyrood TGS DAFOR = 20%, 50 MW imports	1.15	0.76	0.52	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.06	0.65
S8: No LIL, Holyrood TGS DAFOR = 20%, 100 MW imports	0.63	0.41	0.29	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.06	0.38

EUE (MWh)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
S1: Expected Case, Holyrood TGS DAFOR = 15%	0	0	0	0	0	0	0	0	0	0	1	11
S2: Expected Case, Holyrood TGS DAFOR = 18%	0	0	0	0	0	0	0	0	0	0	1	11
S3: Expected Case, Holyrood TGS DAFOR = 20%	0	0	0	0	0	0	0	0	0	0	1	12
S4: No LIL, Holyrood TGS DAFOR = 15%	55	37	27	0	0	0	0	0	0	0	1	35
S5: No LIL, Holyrood TGS DAFOR = 18%,	91	59	41	0	0	0	0	0	0	0	2	52
S6: No LIL, Holyrood TGS DAFOR = 20%	118	79	54	0	0	0	0	0	0	0	3	70
S7: No LIL, Holyrood TGS DAFOR = 20%, 50 MW imports	60	37	27	0	0	0	0	0	0	0	3	37
S8: No LIL, Holyrood TGS DAFOR = 20%, 100 MW imports	31	18	14	0	0	0	0	0	0	0	3	21

Table 7: Monthly LOLH and EUE for 2022

LOLH (hours)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
S1: Expected Case, Holyrood TGS DAFOR = 15%[16]	0.08	0.08	0.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.10
S2: Expected Case, Holyrood TGS DAFOR = 18%	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
S3: Expected Case, Holyrood TGS DAFOR = 20%	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
S4: No LIL, Holyrood TGS DAFOR = 15%	1.32	0.87	0.57	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.03	0.74
S5: No LIL, Holyrood TGS DAFOR = 18%,	1.96	1.29	0.87	0.01	0.00	0.00	0.01	0.00	0.00	0.00	0.06	1.11
S6: No LIL, Holyrood TGS DAFOR = 20%	2.54	1.68	1.10	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.08	1.38
S7: No LIL, Holyrood TGS DAFOR = 20%, 50 MW imports	1.42	0.91	0.61	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.07	0.76
S8: No LIL, Holyrood TGS DAFOR = 20%, 100 MW imports	0.77	0.47	0.33	0.01	0.00	0.00	0.01	0.00	0.00	0.00	0.08	0.44

EUE (MWh)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
S1: Expected Case, Holyrood TGS DAFOR = 15%	8	6	3	0	0	0	0	0	0	0	1	9
S2: Expected Case, Holyrood TGS DAFOR = 18%	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
S3: Expected Case, Holyrood TGS DAFOR = 20%	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
S4: No LIL, Holyrood TGS DAFOR = 15%	71	44	30	0	0	0	0	0	0	0	2	41
S5: No LIL, Holyrood TGS DAFOR = 18%,	106	68	47	0	0	0	0	0	0	0	3	64
S6: No LIL, Holyrood TGS DAFOR = 20%	145	89	63	0	0	0	0	0	0	0	4	84
S7: No LIL, Holyrood TGS DAFOR = 20%, 50 MW imports	74	47	31	0	0	0	0	0	0	0	3	43
S8: No LIL, Holyrood TGS DAFOR = 20%, 100 MW imports	38	21	16	0	0	0	0	0	0	0	4	24

[16] Note that in this case, the Holyrood TGS has been retired as of March 31, 2021 and the results presented reflect the expected reliability of the system under expected conditions in 2022.

Table 8: Monthly LOLH and EUE for 2023

LOLH (hours)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
S1: Expected Case, Holyrood TGS DAFOR = 15%	0.12	0.14	0.06	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.11
S2: Expected Case, Holyrood TGS DAFOR = 18%	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
S3: Expected Case, Holyrood TGS DAFOR = 18%	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
S4: No LIL, Holyrood TGS DAFOR = 15%	1.41	1.03	0.60	0.01	0.00	0.00	0.01	0.00	0.01	0.00	0.04	0.94
S5: No LIL, Holyrood TGS DAFOR = 18%,	2.14	1.56	0.91	0.01	0.00	0.00	0.01	0.00	0.01	0.00	0.07	1.34
S6: No LIL, Holyrood TGS DAFOR = 20%	2.74	2.02	1.16	0.01	0.00	0.00	0.00	0.00	0.01	0.01	0.09	1.70
S7: No LIL, Holyrood TGS DAFOR = 20%, 50 MW imports	1.52	1.07	0.63	0.01	0.00	0.00	0.01	0.00	0.01	0.00	0.09	0.96
S8: No LIL, Holyrood TGS DAFOR = 20%, 100 MW imports	0.83	0.60	0.35	0.01	0.00	0.00	0.01	0.00	0.02	0.01	0.09	0.56

EUE (MWh)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
S1: Expected Case, Holyrood TGS DAFOR = 15%	12	13	6	0	0	0	0	0	0	0	1	8
S2: Expected Case, Holyrood TGS DAFOR = 18%	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
S3: Expected Case, Holyrood TGS DAFOR = 18%	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
S4: No LIL, Holyrood TGS DAFOR = 15%	75	53	32	0	0	0	0	0	0	0	2	54
S5: No LIL, Holyrood TGS DAFOR = 18%,	120	83	49	0	0	0	0	0	0	0	3	78
S6: No LIL, Holyrood TGS DAFOR = 20%	155	111	66	1	0	0	0	0	0	0	5	102
S7: No LIL, Holyrood TGS DAFOR = 20%, 50 MW imports	78	55	34	0	0	0	0	0	0	0	4	56
S8: No LIL, Holyrood TGS DAFOR = 20%, 100 MW imports	41	29	18	0	0	0	0	0	0	0	4	31

Table 9: Monthly LOLH and EUE for 2024

LOLH (hours)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
S1: Expected Case, Holyrood TGS DAFOR = 15%	0.20	0.17	0.09	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.11
S2: Expected Case, Holyrood TGS DAFOR = 18%	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
S3: Expected Case, Holyrood TGS DAFOR = 18%	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
S4: No LIL, Holyrood TGS DAFOR = 15%	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
S5: No LIL, Holyrood TGS DAFOR = 18%,	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
S6: No LIL, Holyrood TGS DAFOR = 20%	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
S7: No LIL, Holyrood TGS DAFOR = 20%, 50 MW imports	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
S8: No LIL, Holyrood TGS DAFOR = 20%, 100 MW imports	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

EUE (MWh)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
S1: Expected Case, Holyrood TGS DAFOR = 15%	19	16	9	0	0	0	0	0	0	0	0	8
S2: Expected Case, Holyrood TGS DAFOR = 18%	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
S3: Expected Case, Holyrood TGS DAFOR = 18%	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
S4: No LIL, Holyrood TGS DAFOR = 15%	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
S5: No LIL, Holyrood TGS DAFOR = 18%,	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
S6: No LIL, Holyrood TGS DAFOR = 20%	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
S7: No LIL, Holyrood TGS DAFOR = 20%, 50 MW imports	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
S8: No LIL, Holyrood TGS DAFOR = 20%, 100 MW imports	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

8.0 Conclusion

Hydro closely monitors its supply-related assets to ensure its ability to provide reliable service to customers. As previously identified by both Hydro and Liberty, the availability of power over the LIL remains very important to system reliability in the near-term. Hydro is working closely with Nalcor's Power Supply leadership to monitor and mitigate the risks associated with the timing of the in-service of the LIL to supply off-Island capacity and energy to the Island Interconnected System. In the case that the LIL in-service date is delayed, there is significant potential exposure to resource shortfalls. If this is the case, there is the potential to mitigate the risk by entering into contracts for firm capacity over the Maritime Link. Following the full in-service of the Muskrat Falls project assets and the retirement of Holyrood TGS, small values of LOLH and EUE continue to be observed in winter months increasing with retirements and increasing system load; however, values are materially reduced from those observed in 2020.

Volume III: Long-Term Resource Plan

Reliability and Resource Adequacy Study 2019 Update
Volume III: Long-Term Resource Plan

November 15, 2019

A report to the Board of Commissioners of Public Utilities

Table of Contents

List of Appendices

List of Attachments

1.0 Introduction

This 2019 update to the Reliability and Resource Adequacy Study ("2019 Update") is filed as a complement to Hydro's "Reliability and Resource Adequacy Study," filed with the Board of Commissioners of Public Utilities ("Board") on November 16, 2019 ("2018 Filing"). It is intended to provide additional detail on matters Newfoundland and Labrador Hydro ("Hydro") has continued to investigate through 2019, responses to findings and recommendations made by The Liberty Consulting Group ("Liberty") in its review "Review of Newfoundland and Labrador Hydro's Reliability and Resource Adequacy Study," filed with the Board August 19, 2019 ("Liberty's Review"), updates on items identified in the action plan included in Hydro's 2018 Filing, and updated identification of timing by which incremental resources are likely to be required based on the 2019 annual assessment.

Volume III of the 2019 Update addresses the long-term resource plan that is required to meet the reliability expectations defined in Volume I. Specifically, the analysis comprehensively evaluates resource options to meet projected future customer demand and energy requirements at least-cost through to 2029.

The resource plan determines the least-cost additional resources required based on the reserve margin targets established by the Reliability Model,[1] as summarized in Volume I of the 2019 Update and described in detail in the 2018 Filing, over the 10-year study period. Key inputs to the resource planning process include the long-term load forecast, resource options and costing, and other forecasts (e.g., fuel, escalation, market prices, etc.). The resource plan also considers the environmental, sustainability, and reliability attributes of all resource options considered.

This resource planning process seeks to minimize power supply costs and risks while maintaining a high degree of system reliability. Conducting forward looking analysis ensures that there is clear line of sight to the timing of incremental resource additions, with the flexibility to react to changes in load forecasts, legislative and regulatory requirements, new technologies, and market price volatilities. Conducting the analysis annually ensures that the recommended courses of action continue to provide the optimal alternative for Hydro's customers in consideration of both cost and reliability.

[1] The reliability model is used to assess anticipated system reliability during the forecast to determine the target planning reserve margin that must be held to satisfy reliability requirements.

From a risk perspective, it is noted that the inputs for the resource planning process are not precise. While many variables, such as forecast retirements and asset health, are analyzed to understand the implications and interaction of inputs and impacts on costs and rates, by nature these variables include uncertainty. Similar to results noted in the 2018 Filing, three variables in particular contribute to the majority of variation observed between identified resource plans:

1) The difference in forecast peak demand associated with the considered range of retail rates for the Island Interconnected System;

2) The difference between the use of P90 versus P50 peak demand forecast in supply planning as the base for the Island Interconnected System forecast; and

3) The option to mitigate the unserved energy resulting from the event that the Labrador-Island Link ("LIL") becomes unavailable for a prolonged period at time of system peak.

As such, the results of this analysis provide an opportunity for discussion with stakeholders on key decision inputs to be used in the future planning of the Newfoundland and Labrador Interconnected System. Further optimization of results will be undertaken as required to support decision-making, and also as part of the annual planning exercise. By conducting this analysis annually the impact of any changes in key inputs that materialize over the course of the year will be included in Hydro's analysis in a timely manner.

The Planning Reserve Margin, detailed in Volume I of the 2019 Update, forms the basis for the addition of incremental resources identified in the Resource Planning process. Another case, which contemplates the investment required to partially and fully mitigate unlikely loss-of-supply events including the loss of the LIL, is further discussed in this update. In that case, the decision to invest in incremental supply is not to satisfy the planning reserve margin, but rather a choice to be made specific to the jurisdiction.

2.0 Consideration of Liberty's Findings and Recommendations

Throughout 2019, Liberty conducted a thorough review of Hydro's 2018 Filing. The review consisted of initial documentation review, on-site interviews, and independent analysis. While Liberty's Review made a number of recommendations, generally Liberty was supportive of much of the work Hydro completed, stating:

> ***"While we recommend testing and validation, and adjustment if thereby warranted, of some methods and criteria, none of our recommendations undercut the value of using the current analysis as a foundation for examining supply reliability risks, consequences, and solutions."***[2]

Hydro has reviewed Liberty's Report and Table 1 highlights each recommendation and where Hydro's response can be found within the 2019 Update. This table is located at the beginning of each volume of the 2019 Update for ease of reference. Recommendations in bold indicate that Hydro's response to Liberty's recommendations can be found in that particular volume of the 2019 Update.

Table 1: Location of Responses to Liberty's Recommendations

Item	Recommendation	Location in the 2019 Update
Study Methods, Assumptions, and Criteria		
1a	**Hydro should promptly examine the likelihood and the range of consequences of an extended bipole LIL outage under extreme weather circumstances,**	**Vol. III, s 7.2.1**
1b	**and should undertake a robust examination of generation options (including continued use of the Holyrood steam units) to mitigate that risk.**	**Vol. III, s 5.6.1**
2	**Hydro should promptly commence a stakeholder engagement process to address Value of Loss Load ("VOLL"), informed by a sound contemporaneous examination of extended bipole outage risk and the options, including extension of generation at Holyrood, for mitigating that risk.**	**Vol. III, s 3.1**

[2] "Review of Newfoundland and Labrador Hydro's Reliability and Resource Adequacy Study," The Liberty Consulting Group, August 19, 2019 at p. 17.

Item	Recommendation	Location in the 2019 Update
3	Hydro should continue to reflect both P50 and P90 weather conditions as part of its efforts to assess system reliability and economy as it acquires more information in the coming months.	Vol. I, s 4.2.4
4	Hydro should verify that its means for addressing the relationship between planning and operating reserve margins does not introduce significant error.	Vol. I, s 4.2.1
5	Hydro should promptly analyze whether differences in its system and those of Manitoba Hydro and Hydro Quebec have any implications for benchmarking its planning reserve margin.	Vol. I, s 6.5.1
Long-Term Reliability		
6	Hydro should establish a plan and schedule for integrating the results of the current examination and subsequent processes for considering factors affecting future electrical requirements and non-generation means for influencing load and usage into a re-analysis of its future needs under a robust range of circumstances and scenarios.	Executive Summary
7	**Promptly conduct the analyses necessary to assess short-term and indefinite extension of Holyrood's life as a supply reserve.**	**Vol. III, s 4.1.1**
Near-Term Reliability		
8	Immediately conduct a detailed assessment of the impacts of a delay in LIL operation into and past the coming winter.	Vol. II, s 4.2.1
9	**Resolving the issues that have surrounded LIL monopole availability should continue to form a critical focus and Hydro should ensure that longer-term uncertainties about Holyrood's future do not lead to decisions that compromise its ability to operate reliably now.**	**Vol. III, s 4.1.1**
Extended LIL Outages		
10	**Hydro should conduct a detailed analysis quantifying the probabilities and restoration durations for a robust range of bipole LIL outages.**	**Vol. III, s 7.2.1**
11	**Hydro should complete remaining steps to prepare for LIL outages as soon as possible.**	**Vol. III, s 7.2.1**
Generation Asset Reliability		
12	**Engage an entity with substantial experience in boiler construction and repair to conduct a detailed assessment of Holyrood's major systems.**	**Vol. III, s 5.6.1**

With respect to recommendation #13, Hydro appreciates Liberty's suggestions for further enhancements to its asset management processes. Hydro is considering items noted by Liberty for inclusion in its asset maintenance program.

3.0 Stakeholder Engagement

Hydro conducted stakeholder engagement in support of the 2018 Filing to complement the technical assessments and fully inform the recommended resource plan. This involved direct consultation, specifically focused on reliability and resource planning, with Newfoundland Power, Hydro's Industrial Customers, the Consumer Advocate, and provincial electricity customers.

Hydro worked with National Public Relations, an external communications consultant, and Corporate Research Associates ("CRA") to implement a digital engagement initiative designed to provide an opportunity for residents and businesses to become actively engaged in the conversation on electricity in the province. The initiative provided qualitative information that was used to inform recommendations and key conclusions of the 2018 Filing. A full discussion of the initiatives and the results obtained from Hydro's engagement can be found in Volume III, Section 2 of the 2018 Filing.

Hydro met with its industrial customers, i.e., Corner Brook Pulp and Paper Limited ("CBPP"); Praxair Canada Inc.; Teck Resources Limited; and Vale Newfoundland and Labrador Limited ("Vale"), in 2018 to provide an overview of the study and provide an opportunity for stakeholders to ask questions and provide feedback. Overall, the industrial customers generally agreed with the proposed approach for study execution, with many commenting on the comprehensiveness of the presented project scope.

Hydro also consulted with Newfoundland Power and the Consumer Advocate in the development of study scope and areas of focus throughout the study execution. As the majority of retail customers on the Island Interconnected System are served by Newfoundland Power, Newfoundland Power executives were consulted on the overall study methodology and the customer engagement strategy. Additionally, Newfoundland Power staff was engaged on matters including the modelling of Newfoundland Power assets in Hydro's models, the consideration of rate design as a resource option, and Customer Demand Management ("CDM"). In consultation with the Consumer Advocate, it was noted that the inclusion of CDM and rate design as potential resource options marked a positive step forward. The Consumer Advocate stated that customers continue to be concerned about future electricity costs and would likely benefit from additional flexibility and options. Stakeholders were provided with opportunities to provide input on study considerations and methodology, with recommendations incorporated.

3.1 Liberty's Review and Recommendations

Liberty noted that stakeholder engagement is informative, with the value of the engagement increasing when considering the potential rate dislocation given the costs associated with the Muskrat Falls project. Liberty further noted that the results of Hydro's engagement were qualitative in nature, and do not provide substantive guidance in analyzing the specific trade-offs between cost and reliability.

Liberty's Recommendation #2:

"Hydro should promptly commence a stakeholder engagement process to address VOLL, informed by a sound, contemporaneous examination of extended bipole outage risk and the options, including extension of generation at Holyrood, for mitigating that risk."[3]

Hydro's 2018 engagement effort was intended to be a first step in beginning an ongoing dialogue for residents and businesses to become actively engaged in the conversation on electricity in the province. Hydro accepts Liberty's recommendation to address the value of loss load ("VOLL") as a method of determining the cost sensitivity of provincial electricity customers to outages.

To ensure development of a meaningful assessment of VOLL, Hydro intends to engage an external consultant with expertise in this area and a strong background in economics. This initiative would be Hydro's first engagement with provincial electricity customers intended to obtain quantitative results. To Hydro's knowledge, such an assessment has never been undertaken in the Atlantic region. As such, there is a limited local knowledge base on how to successfully complete such an engagement. Hydro will need to find a party with sufficient experience and expertise to develop, execute, and analyze the results of the VOLL to successfully fulfill the engagement. Hydro anticipates working closely with the engaged party to ensure the process and outcomes are developed in consideration of this particular jurisdiction.

In the assessment, special consideration must be given to the outage conditions that would occur in the event of the prolonged loss of the LIL bipole as the majority of VOLL studies focus on outages of shorter

[3] "Review of Newfoundland and Labrador Hydro's Reliability and Resource Adequacy Study," The Liberty Consulting Group, August 19, 2019 at p. 22.

duration (e.g., outages of up to four hours are generally considered in the material Hydro has reviewed), this may take careful study design to ensure the impact and also the mitigating costs are properly assessed, given the sensitivity of VOLL to outage attributes (i.e., duration, frequency, time, magnitude). Finally, to fully address Liberty's recommendation, Hydro may require additional information on the costs associated with incremental resources including the potential for extension of generating operations at the Holyrood Thermal Generating Station ("Holyrood TGS"), and additional information on probabilities and restoration times associated with LIL bipole outages. As the applicable information is received, Hydro will incorporate it into its analysis as appropriate.

Hydro expects to issue a Request for Proposals to ("RFP") to engage an external entity in first quarter of 2020, with the intention of awarding the work in the same quarter. Once developed, Hydro will share a detailed project scope and schedule with the Board for the execution of this work. Hydro anticipates that this work could take between six and eight months to complete, and proposes to include its findings in the 2020 annual update to the 2018 Filing.

4.0 Existing Assets and Infrastructure

4.1 Summary of Existing Assets and Infrastructure

Hydro's existing assets and infrastructure continue to play a key role in its supply mix through the study period. Through the resource planning process, the availability and reliability of existing assets ensure that the system is not relying on assets beyond the expected capability of those assets, and that the firm capability and forced outage rates are appropriately considered. The long-term resource planning model ("Resource Planning Model") uses the criteria determined using the Reliability Model to determine the least-cost alternative to meet system reliability expectations. The majority of the assumptions made in the Resource Planning Model are consistent with those made in the Reliability Model. For more detailed information of the existing assets and infrastructure that are part of the Newfoundland and Labrador Interconnected System generation resources, please refer to Volume II, Section 3 of the 2018 Filing. Detailed information on updated forced outage rates used in the 2019 Update can be found in Attachment 1 to this volume. A summary of Hydro's existing generation assets is listed in Table 2.

Table 2: Summary of Generation Assets at Test Year[4]

Generation Assets	Generation (MW)
Hydraulic Generating Units	
Muskrat Falls	
Unit 1	197.5
Unit 2	197.5
Unit 3	197.5
Unit 4	197.5
Subtotal Muskrat Falls Plant[5]	**790.0**
Bay d'Espoir	
Unit 1	76.5
Unit 2	76.5
Unit 3	76.5
Unit 4	76.5
Unit 5	76.5
Unit 6	76.5
Unit 7	154.4
Subtotal Bay d'Espoir Plant	**613.4**
Cat Arm	
Unit 1	67.0
Unit 2	67.0
Subtotal Cat Arm Plant[6]	**134.0**
Other Hydro	
Hinds Lake	75.0
Granite Canal	40.0
Paradise River	8.0
Upper Salmon	84.0
Mini Hydro	-
Subtotal Other Hydro	**207.0**
Total Hydraulic Generation	**1,744.4**
Thermal Generating Units	
Gas Turbines	
Happy Valley Gas Turbine	25.0
Holyrood Gas Turbine	123.5
Subtotal Gas Turbine	**148.5**

[4] Totals may not add due to rounding.
[5] Difference in Installed Capacity and Gross Capacity is related to potential tailrace icing conditions in the Churchill River in the winter period. This is based on preliminary analysis and will be evaluated as operating data is obtained with the dam and plant is in place.
[6] Following environmental assessment, the Holyrood diesels are rated to produce 8.5 MW on a continuous basis for long-term planning.

Generation Assets	Generation (MW)
Diesels	
Holyrood Diesels[7]	8.5
Hawkes Bay Diesel Plant	5.0
St. Anthony Diesel Plant	9.7
Subtotal Diesel	**23.2**
Total Thermal Generation	**171.7**
Power Purchase Agreements	
Nalcor Energy Exploits[8]	
Grand Falls and Bishop's Falls	63.0
Star Lake	18.0
CF(L)co:	
Recapture Energy	300.0
TwinCo Block	225.0
St. Lawrence Wind	6.0
Fermeuse Wind	6.0
Rattle Brook	-
New World Dairies	-
Total Power Purchases	**618.0**
Total NLH System Supply	**2,533.6**
Other Island Generation Sources	
Newfoundland Power (Hydro)	71.5
Newfoundland Power (Standby)	39.0
Total Newfoundland Power	**110.5**
Total Deer Lake Power Owned	**99.1**
Total System Supply	**2,743.7**

4.1.1 Short-Term Extension of Holyrood Thermal Generating Station

As indicated in Hydro's correspondence to the Board dated October 31, 2019, based on the established schedule for power delivery from the Muskrat Falls project, the Holyrood TGS is expected to have all three units available for operation at full capacity until March 31, 2021. Beyond that date, Unit 3 at the Holyrood TGS will continue to operate as a synchronous condenser, while Units 1 and 2 are scheduled to be shut down and decommissioned.

[7] Following environmental assessment, the Holyrood Diesels are rated to produce 8.5 MW on a continuous basis for long-term planning.
[8] The Nalcor Energy Exploits facility has an installed capacity of 95.6 MW.

The existing capital and operating and maintenance plans for the Holyrood TGS have been developed based on this schedule. The existing capital plan includes projects to facilitate steam generation from all units to March 31, 2021. The capital plan also includes projects for the conversion of Unit 3 to a dedicated synchronous condensing unit and projects required to support synchronous condensing operation into the future. The operating and maintenance plans, likewise, are constructed around the staffing and maintenance required to operate the Holyrood TGS as a fully capable generating facility until March 31, 2021 and a single-unit synchronous condensing facility beyond that date.

Liberty's Review and Recommendations

In Liberty's Review, it was suggested that the Holyrood TGS may be a suitable resource option to provide additional reliability in the event of the LIL bipole outages, noting that the Holyrood TGS units exhibit an operating age and a set of conditions that make them options that Hydro should consider for ensuring supply reliability short- and long-term.

Liberty's Recommendation #7:

"Promptly conduct the analyses necessary to assess short-term and indefinite extension of Holyrood's life as a supply resource."[9]

Liberty also noted that the incremental costs of extending operation of the Holyrood TGS as a generating facility during a phase-in of the Muskrat Falls project assets may be such that the Holyrood TGS is a competitive option to bolster system reliability in the long-term. As such, Liberty stated that prompt study ought to be undertaken to understand the costs and efforts required to provide the units with suitable characteristics and sufficient availability and reliability.

[9] "Review of Newfoundland and Labrador Hydro's Reliability and Resource Adequacy Study," The Liberty Consulting Group, August 19, 2019 at p. 30.

Liberty's Recommendation #9:

"Resolving the issues that have surrounded LIL monopole availability should continue to form a critical focus and Hydro should ensure that longer-term uncertainties about Holyrood's future do not lead to decisions that compromise its ability to operate reliably now."[10]

The current delays in the reliable supply of energy from the Muskrat Falls project make it prudent to identify any changes to existing capital and operating and maintenance plans required to enable the Holyrood TGS to be available to reliably supply customers while the project assets are being placed in-service and proven reliable. Details with respect to contingency plans to enable short-term continued operation of the Holyrood TGS beyond April 2021 (Phase One) follow.

While investigation is ongoing and Hydro is not recommending implementation of these contingency plans at this time, the details are provided to further inform the discussion regarding the provision of reliable supply for customers. By the end of 2019, Hydro will be better informed to decide whether extended operation of Holyrood TGS is required beyond March 31, 2021. At that time, Hydro expects to have more clarity surrounding key milestones associated with the Muskrat Falls project. In January 2020 Hydro will provide the Board with its decision regarding a short-term extension (i.e., one to two years).

Phase One

In this phase, all three units at the Holyrood TGS will be able to operate reliably, whether online in generation mode or in hot-standby mode. Further, when operating in hot-standby mode, units must be able to be recalled from standby to provide generation to the grid within four to eight hours. This mode of operation is currently planned to April 2021 but could be extended to March 31, 2023 with additional investment. If this period were extended, it is expected that the overall energy produced by these units would be reduced considerably from recent years due to availability of energy over the LIL. Operationally, the Holyrood TGS units could be either online at minimum output or in hot-standby as a backup for the loss of the LIL bipole, depending on the reliability of assets and system requirements.

[10] "Review of Newfoundland and Labrador Hydro's Reliability and Resource Adequacy Study," The Liberty Consulting Group, August 19, 2019 at p. 35.

A listing of projects and operation and maintenance activities required to extend operation at the Holyrood TGS by one to two years is provided as Appendix A. Hydro plans to submit supplemental capital budget applications for additional condition assessment work required at the Holyrood TGS to be executed in the first quarter of 2020. Hydro will seek appropriate Board approval for any other capital expenditures, as required.

4.2 Capacity Assistance

Capacity assistance refers to contracted curtailable loads and emergency customer generation. Capacity assistance agreements are generally restricted in terms of frequency, duration, and annual usage. There is currently up to 105 MW of capacity assistance contracted from CBPP through to 2022.

4.3 External Markets

Currently, the Nova Scotia Block[11] is the only firm capacity export included in Hydro's analysis. Nova Scotia Block deliveries are included in the analysis beginning with the in-service of the third unit at the Muskrat Falls Generating Station ("MFGS") and is modelled as 0.986 TWh per year (measured at MFGS) in equal daily quantities for 16 on-peak hours per day, 365 days year. Hydro's analysis also includes delivery of the Supplemental Block[12] which commences with the delivery of the Nova Scotia Block. This agreement provides additional firm energy to Nova Scotia Power annually in off-peak hours over a five-month time period (November to March). The obligation to deliver the Supplemental Block expires five years after it begins.

5.0 Expansion Resource Options Under Consideration[13]

5.1 Summary of Considered Resource Options

The resource planning process identifies when incremental resources are required and which resource options fulfill Hydro's mandate of least-cost reliable supply by selecting the optimum resource mix from the portfolio of available resource options. Volume III, Section 4 of the 2018 Filing provides detailed information, including a brief project description, project-specific potential issues, and risks and a Class 5 estimate for the current portfolio of identified alternatives which may be considered to fulfill future

[11] The Nova Scotia Block is a firm annual commitment of 980 GWh, to be supplied from the MFGS on peak.
[12] Supplemental Energy refers to an additional firm energy commitment to supply energy to Nova Scotia during the first five years of production at the MFGS as part of the Amended and Restated Energy and Capacity Agreement.
[13] Refer to "Reliability and Resource Adequacy Study," Newfoundland and Labrador Hydro, September 6, 2019 (rev. 2), originally filed November 16, 2018, vol. III, att. 4 for details on resource options not considered.

resource requirements. Project costs have been escalated to 2019 dollars in support of this update. Hydro's analysis considered the following resource options:

- Wind Generation;
- Solar Generation;
- Battery Storage Technology;
- Capacity Assistance;
- Rate Design and Customer Demand Management;
- Market Purchases;
- Hydroelectric Generation:
  - New facilities; and
  - Additional units at existing facilities;
- Thermal Generation:
  - Simple cycle gas turbines ("GT"); and
  - Combined cycle combustion turbines; and
- Extended Operation of the Holyrood TGS.

5.2 Capacity Assistance and Curtailable Load

Subject to transmission constraints, capacity assistance continues to be a viable expansion alternative. While this option has not been modelled explicitly beyond the term of currently existing contracts, as Hydro approaches a capacity deficit in the future, this option would be evaluated against other resource options.

5.3 Rate Structures and Customer Demand Management

While additional supply can be acquired to meet increased customer requirements, rate design and CDM activities can also be undertaken to promote a reduction in customer demand and/or energy requirements. Hydro's study of these alternatives continued throughout 2019 as described in the following sections.

5.3.1 Critical Peak Pricing

One area of interest for Hydro is critical peak pricing ("CPP"), a rate structure whereby customers are motivated to reduce consumption during system peaks. Hydro-Québec is conducting a critical peak pricing pilot program during the winter of 2019–2020.[14,15]

Participants in the Hydro-Québec program can choose from one of two programs: 1) Rate Flex or 2) the Winter Credit Option. Under the Rate Flex alternative, customers are offered a discount of 17% on the standard base rate during winter; however, electricity is priced materially higher than the standard base rate during peak demand events (50 cents per kWh).[16] The Winter Credit Option is marketed as a risk-free alternative to Rate Flex. The Winter Credit Option allows customers to receive a credit if they reduce their electricity consumption during peak demand events, but does not offer a discount from the standard base rate during non-peak demand events. During a peak demand event, customers will receive a 50 cent credit for every kWh curtailed (i.e., not consumed compared to their usual energy use).[17]

Hydro will continue to monitor Hydro-Québec's CPP pilot study to help determine if a similar program could have potential for customers in Newfoundland and Labrador, in the context of Newfoundland Power's upcoming rate design review.

5.3.2 Dunsky Energy Consulting Conservation Potential Study

Through 2018 and 2019, Newfoundland Power and Newfoundland and Labrador Hydro jointly executed a CDM potential study. The objectives of that study were to identify achievable, cost-effective electric energy and demand management measures to reduce or shift peak demand, outline general parameters for program development, and quantify achievable savings potential by sector and end use in the province.

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[14] Dynamic Pricing. Hydro-Québec <http://www.hydroquebec.com/business/customer-space/rates/dynamic-pricing.html> and Rates for residential customers. Hydro-Québec <http://www.hydroquebec.com/residential/customer-space/rates/>
[15] Enrollment in the program is limited to 18,000 participants.
[16] Peak demand events can take place weekdays from December 1 to March 31 between 6-9 am and 4-8 pm. Maximum of 33 events with total maximum of up to 100 hours overall.
[17] There is no penalty for customers under this rate option, only the opportunity to achieve a bill credit for curtailed usage during peak demand events.

The study was conducted by Dunsky Energy Consulting ("Dunsky").[18] Results of the study were made available in June 2019. The study considered a fifteen year period, from 2020 to 2034, and assessed a number of components including:

- Energy Efficiency;
- Demand Response;
- Fuel Switching; and
- Electric Vehicles ("EV").

As noted in the Dunsky study:

> While TOU Rates, CPP and Equipment Control programs did not appear to offer additional DR potential, adjustments to the existing Industrial Curtailment programs, incorporating more aggressive EV adoption peak load impacts, or adding the Fuel Switching load curve impacts, all may alter conditions such that TOU Rates, CPP and/or Equipment Controls could become effective in the future: Changes to the utility load curve or to the constraints applied in other programs have significantly impacted the interactions among programs. For example, if the NL Utilities are able to negotiate Industrial Curtailment contracts with longer DR event durations, it may be possible that TOU Rates, CPP and Equipment Programs could offer additional potential as compared to the results presented herein.[19]

Hydro and Newfoundland Power have requested that Dunsky study the impact that revised Capacity Assistance Agreements could have on its conclusions regarding CPP and Time of Use ("TOU") rates. The results of this additional study are expected in 2020.

5.3.3 Electric Vehicles

Based on the Dunsky study and the Synapse Energy Economics, Inc. ("Synapse") report on the Reference on Rate Mitigation Options and Impacts Relating to the Muskrat Falls Project Costs ("Reference Question"),[20] electric vehicle adoption in Newfoundland and Labrador has the potential to increase sales and contribute to rate mitigation over the long term. As noted in the Dunsky study, the most significant impact in accelerating electric vehicle adoption would result from investments in Level 3 charging

[18] "Conservation Potential Study," Dunsky Energy Consulting (6893449 Canada Inc.), Final Report (Volume 1 – Results)
[19] "Conservation Potential Study," Dunsky Energy Consulting (6893449 Canada Inc.), Final Report (Volume 1 – Results), at p. xii.
[20] "Phase 2 Report on Muskrat Falls Project Rate Mitigation," Synapse Energy Economics, Inc., September 25, 2019 (rev. 1).

stations. The study suggested that such investments could potentially result in 647 GWh in additional electric vehicle load by 2034.

The contribution to peak demand resulting from electric vehicle adoption would need to be managed carefully. Synapse recommended the use of 'smart' electric vehicle chargers to allow for time of use rates with respect to electric vehicle charging to stimulate off-peak charging by customers. Further, Hydro notes that utility controlled smart electric vehicle chargers are currently being tested in other jurisdictions.[21]

During its presentation of the 2019 Budget, the Government of Newfoundland and Labrador committed to increase electric vehicle usage in Newfoundland and Labrador.[22] Hydro is planning to develop a network of 14 direct current fast chargers from St. John's to Port Aux Basques in 2020, conditional on funding approvals. As electric vehicles become more common in Newfoundland and Labrador, programs and incentives will need to be examined to encourage off-peak charging behaviors.

5.3.4 Heat Pumps

Both the Synpase and Dunsky studies commented on the material increase in heat pump usage on the Island Interconnected System and the potential for additional conversions to the use of heat pumps. To provide increased understanding of system load impacts of peak usage attributes of heat pumps, Newfoundland Power is undertaking a heat pump load research study. The objective of the heat pump load research project is to understand the impact that increasingly high penetration of heat pumps will have on the Island Interconnected System demand and peak load requirements.

The results of this study will inform future CDM program design, customer education and system load forecasts.

5.4 Market Purchases

While this option has not been modelled explicitly, as Hydro approaches a capacity deficit at any time in the future, Hydro anticipates it would engage Nalcor Energy Marketing ("NEM") to conduct a detailed market sounding for capacity and/or energy as required.

[21] "Charge TO Report: How Utilities could reduce EV peak load by over 50%," fleetcarma <https://www.fleetcarma.com/power-utilities-how-to-reduce-peak-load-50-percent/>
[22] "Budget 2019 Working towards a brighter future Budget Speech," Government of Newfoundland and Labrador, April 16, 2019 <https://www.gov.nl.ca/budget/2019/wp-content/uploads/sites/2/2019/04/Budget-Speech-2019.pdf>

5.5 Simple-Cycle Gas Turbine

Hydro's 2018 Filing included Class 5 cost estimates for the construction of GT plants to be considered as resource options. These nominal 66 MW (58.5 MW net), simple-cycle GTs would be located either adjacent to the existing unit at the Holyrood site, considered to be a brownfield site, or at greenfield locations. GTs considered are light oil-fired and, given the unit efficiency, are primarily intended for peaking and voltage support functions. The option considered includes fuel storage capacity to allow continuous operation for a minimum of five days. While these units are considered to support capacity-driven requirements, each is capable of providing approximately 460 GWh of firm energy capability annually. Table 3 provides a summary of the GT alternatives considered.

Table 3: Gas Turbine Alternatives

Type	Number of Units	Net Capacity (MW)	Capital Cost ($ million)
Simple Cycle Plant	1	58.5	169
Simple Cycle Plant	2	117	298
Simple Cycle Plant	4	234	664

Single-line diagrams were prepared for four potential sites on the eastern Avalon Peninsula to assist in the development of the project estimates; Bremigan's Pond, Paddy's Pond, Sugar Loaf Pond, and the existing Holyrood facility.

The estimates were prepared in consultation between Hydro's mechanical, civil, electrical and transmission and distribution engineering departments. Hydro's simple cycle 123.5 MW GT plant constructed in 2015 was used as a reference, along with new budgetary information received from major GT manufacturers and the contractor that constructed the 123.5 MW plant. Following completion of the estimates Hydro engaged an external consultant to review and provide an opinion on accuracy. The consultant reported that all estimates were at least Class 5 and probably Class 4.

5.6 Consideration of Holyrood Thermal Generating Station as a Long-term Resource Option

As described in section 4.1.1, Holyrood TGS is expected to have all three units available for operation at full capacity until March 31, 2021. Beyond that date Hydro expects Unit 3 at Holyrood TGS will continue to operate as a synchronous condenser, while Units 1 and 2 are scheduled to be shut down and decommissioned.

5.6.1 Liberty's Review and Recommendations

Liberty's Review included an assessment of the condition of Holyrood TGS, using data provided by Hydro and reports filed with the Board as the primary sources of data. Upon review, Liberty noted the condition of the Holyrood TGS units also makes them logical candidates to consider as alternatives for ensuring system reliability longer term should additional generating sources on the Island Interconnected System be considered.

> ***Liberty's Recommendation #1b:***[23]
>
> ***". . . and should undertake a robust examination of generation options (including continued use of the Holyrood steam units) to mitigate that risk."***[24]

Liberty's Review also included high level commentary on a number of attributes of the Holyrood TGS major systems and equipment including:

- Steam Boilers;
- Combustion Air Systems;
- Steam Turbine Generator;
- Feedwater and Condensate;
- Cooling Water Systems;
- Electrical and Control Systems;
- Main Condensers and Water Boxes;
- Main Stacks; and
- Fuel Oil Tanks.

In particular, Liberty suggested a more detailed boiler assessment was required to ensure that no other major reliability-affecting boiler issues exist, and that an inspection of the combustion air systems was

[23] Hydro has divided recommendation 1 from Liberty's Review into two separate parts, designated a and b, to ensure the question has been fully addressed.
[24] "Review of Newfoundland and Labrador Hydro's Reliability and Resource Adequacy Study," The Liberty Consulting Group, August 19, 2019, at p. 21.

also warranted to identify potential issues that could impede reliability should the operation of the plant be extended.

> ***Liberty's Recommendation #12:***
>
> ***"Engage an entity with substantial experience in boiler construction and repair to conduct a detailed assessment of Holyrood's major systems."[25]***

As discussed in section 4.1.1, the current delays in the reliable supply of energy from the Muskrat Falls project makes it prudent to identify any changes to existing capital and operating and maintenance plans required to enable the Holyrood TGS to continue to be available to reliably supply customers while the project assets are being placed in-service and proven reliable. As Liberty has suggested, it could be possible to extend operation at Holyrood TGS beyond the short-term extension of operations contemplated in Phase One. In response to Liberty's recommendation, Hydro is developing contingency plans that would enable indefinite operation of the Holyrood TGS (Phase Two).

Phase Two

This phase entails indefinite stand-by operation of Holyrood TGS from April 2023:

- Holyrood TGS Units 1 and 2 would remain offline but capable of generating 170 MW each;
- Unit 3 will be operating as synchronous condenser but will remain capable of being converted to generate mode at 150 MW;
- Target recall times for Units 1 and 2 of 24 and 48 hours will be considered; and
- Assessment of the feasibility to reduce the time required to convert Unit 3 from synchronous condenser to generate mode.

Hydro is in the process of developing an application for supplemental capital expenditures to engage an entity with extensive boiler experience to conduct a major systems review and life extension requirements study for the Holyrood TGS. The third party has not yet been identified as Hydro plans to

[25] "Review of Newfoundland and Labrador Hydro's Reliability and Resource Adequacy Study," The Liberty Consulting Group, August 19, 2019 at p. 63.

issue an RFP to engage an entity to complete this work. Hydro expects that the scope of the assessment will include but not necessarily be limited to:

- A full condition assessment of all major systems components of the Holyrood TGS units and plant, including internal inspections. This will also include a review of previously completed condition assessments including those conducted from 2011 through 2018;
- Development of an appropriate capital plan to support indefinite operations of these assets as generators;
- Identification of required operation and maintenance strategy for indefinite operation;
- Identification of required operator training and competency requirements;
- Review of unit start-up times including the physical and procedural changes required to reduce the same;
- Recommendations on minimum operating loads;
- Assessment of equipment lay-up requirements;
- Assessment of Unit 3 synchronous condenser conversion times;
- A review of standby operation targets in industry including recommendations;
- Recommendations on staffing level requirements; and
- Recommendations with respect to environmental considerations including legislative requirements and requirements for the Certificate of Approval to Operate, which is issued by the Provincial Government.

Hydro expects that once an entity is engaged, it will be able to provide a detailed schedule for the Board's consideration. Given that the detailed inspection contemplated will be required to take place during the maintenance season, Hydro anticipates the study will require approximately 10 months to complete, which accounts for the staggering of annual maintenance outages on the units allowing for physical access to key equipment.

Following completion of this work, Hydro expects to file a report by January 29, 2021 detailing the requirements to support longer term, indefinite operation. This report will inform decision making with respect to the suitability of the Holyrood TGS as a longer term back-up resource option. Hydro could then model the option as a candidate resource.

6.0 Load Forecasts

The purpose of load forecasting is to project electric power demand and energy requirements through future periods. This is a key input to the resource planning process, which ensures sufficient resources are available consistent with applied reliability standards. For the Newfoundland and Labrador Interconnected System, the load forecast is segmented by the Island Interconnected System and Labrador Interconnected System, as well as by utility load (i.e., domestic and general service loads of Newfoundland Power and Hydro) and industrial load, i.e., larger direct customers of Hydro such as CBPP, North Atlantic Refining Ltd, Vale, and Iron Ore Company of Canada(“IOC”). The load forecast process entails translating a long-term economic and energy price forecast for the province into corresponding electric demand and energy requirements for the electric power systems.[26,27]

The resource planning process considers a range of potential forecast scenarios, rather than a single forecast. This allows for evaluation of the sensitivity of results to differing economic conditions. For this planning exercise, a range of forecasts were developed independently for the Island and Labrador. The combination of those forecasts with evaluation of both the P50 and the P90 conditions for the Island Interconnected System as discrete scenarios resulted in the evaluation of 12 discrete scenarios.[28] A visualization of the scenarios considered is presented in Figure 1.

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[26] Long-term economic forecast for the province is taken from “Budget 2019 Working towards a brighter future Budget Speech,” Government of Newfoundland and Labrador, April 16, 2019 <https://www.gov.nl.ca/budget/2019/wp-content/uploads/sites/2/2019/04/Budget-Speech-2019.pdf> The forecast also takes into account the Government of Newfoundland and Labrador’s currently planned building electrifications.

[27] Local fuel price projection derived from S&P Global’s long-term oil price forecast, Spring 2019.

[28] 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). 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.

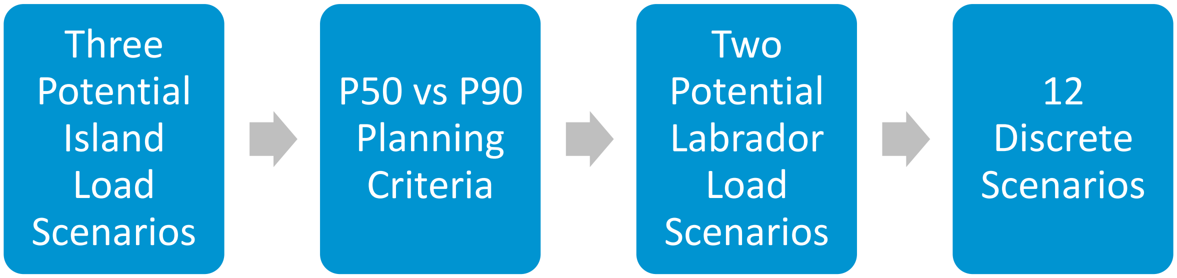

Figure 1: Modelled Scenarios

6.1 Economic Variability based on Provincial Economic Overview

Newfoundland and Labrador continues to experience a transitionary period, conditioned by major projects reaching completion and new developments waiting to be realized.

In 2018, Newfoundland and Labrador's economy continued to adjust, with major projects having reached final development and production phases in 2017 (e.g., ExxonMobil's Hebron offshore oil project and Vale's Long Harbour Processing Plant) and the Muskrat Falls project having entered its final development stage, resulting in lower levels of capital investment. Despite this, investment levels within the province remained high compared to pre-2012 levels.

A labour dispute at the IOC resulted in two months of suspended production in 2018, contributing to a decrease in the export value of goods and services over 2017. The decrease in provincial mineral production in 2018 was partially offset by increased oil production that was positively influenced by Hebron oil production. The seafood sector remained a significant contributor to the provincial rural economy despite the fishery and aquaculture sectors experiencing decreases in both volume and value of product in 2018. Tourism activity also slowed in 2018 relative to 2017. Overall economic activity in the province decreased, with real gross domestic product ("GDP") decreasing by 2.9 percent from 2017. On a positive note, employment levels experienced a small gain, increasing by 0.5% compared to 2017 and ending a four-year decline in employment.

Looking forward through the medium-term (i.e., one to five years) there are several developments that will positively influence provincial economic activity, both in Labrador and on the island. In late 2018, Greig NL's Placentia Bay aquaculture project was released from environmental assessment and the project is expected to be fully operational by 2025. Increased interest in aquaculture is expected to expand the overall fishing and aquaculture industry.

The mining sector also announced encouraging developments, including Vale's announcement that it will proceed with the development of two underground mines at Voisey's Bay, resulting in a large capital investment and a long-term source of nickel concentrate for the Long Harbour Processing Plant. Additionally in 2018, Tacora Resources secured funding to restart the former Wabush Mines, with operations resuming in 2019.

Over the medium term, adjusted real GDP is forecast to decline, being partially offset with increases in exports, driven by new energy and mining projects. Capital investment is also expected to increase, due to increased investment for the West White Rose project and development at Voisey's Bay. According to current provincial economic reports by many Canadian financial institutions, it is anticipated that increases in both capital investment and exports will help achieve a modest bounce-back in Newfoundland and Labrador's economy from 2018 levels.[29,30]

While the current Provincial Government's fiscal situation remains relatively challenging and an overall weak economic environment exists, the underlying local market conditions for electric power operations through the medium and longer term in the context of provincial energy requirements suggest stable energy requirements in the near to medium term with modest increases in the longer term.[31] Table 4 provides the provincial economic assumptions, as forecast by the Department of Finance, Government of Newfoundland and Labrador. [32] These inputs form the basis of Hydro's load forecast models.

[29] "Provincial Outlook," RBC, June 2019, <http://www.rbc.com/economics/economic-reports/pdf/provincial-forecasts/nl.pdf>
[30] "Provincial Economic Forecast," TD Economics, June 17, 2019 <https://economics.td.com/domains/economics.td.com/documents/reports/pef/ProvincialEconomicForecast_Jun2019.pdf>
[31] The energy outlook is conditioned by electricity prices in which the customer rate impacts of the Muskrat Falls Project are assumed to be extensively mitigated.
[32] "Budget 2019, Working towards a brighter future," Government of Newfoundland and Labrador, <https://economics.gov.nl.ca/E2019/TheEconomy2019.pdf>

Table 4: Provincial Economic Indicators – 2019 Planning Load Forecast

	2018-2024	2018-2030
Adjusted Real GDP at Market Prices[33] (% per year)	-1.4%	0.0%
Real Disposable Income (% per year)	0.3%	0.6%
Average Housing Starts (Number per year)	1,132	1,141
End of Period Population (000s)	519.8	519.5

6.2 Considered Potential Island Load Scenarios

Total Island Interconnected System load is the summation of interconnected utility load, industrial customer loads, as well as bulk transmission and distribution losses incurred serving the customer load requirements on the system.

Three scenario cases were developed for the Island Interconnected System based on consideration of potential retail electricity rates and provincial economic growth. Table 5 presents the forecast scenarios for utility load growth on the Island Interconnected System that includes the load requirements for Newfoundland Power and Hydro's rural customers. Of note is the range of load change possibilities for the Island Interconnected System, which is driven by the provincial economic outlook and the uncertainty of electricity rates. Cases I and II are representative of the base provincial economic forecast with varying electricity price forecasts.[34] Case III is representative of a high growth provincial economic forecast and the mitigated rate forecast consistent with Case I.[35] Through the medium term, the economic growth expectations for the province coupled with the alternate rate outlook indicate utility load requirements are primarily dependent on the level of rates during the period. The load forecast results also indicate that the extent of positive growth in the longer term period will also be dependent

[33] Adjusted GDP excludes income that will be earned by the non-resident owners of provincial resource developments to better reflect growth in economic activity that generates income for local residents.
[34] The changes in customer loads indicated by Cases I and II are associated with alternate electricity price futures, which influences future load requirements through price elasticity effects. The price elasticity impacts on future retail electricity consumption levels are based on empirically estimated price elasticities measured from retail customers' historical electricity consumption and price level patterns. There is also cross-price elasticity effects associated with the price of furnace oil, which impacts residential electricity consumption levels in the load forecasts.
[35] The rate forecast used in Case I and Case III aligns with the Government of Newfoundland and Labrador's mitigation target of 13.5 cents per kWh, escalating at 2.25% per year.

on the level of rates but in addition can be expected to be influenced by the level of provincial economic growth.

Table 5: Island Utility Electricity Load Growth Summary – 2019 Planning Load Forecast[36]

		2018–2024[37]	2018–2030
Case I: Mitigated Rate	MW	7.0%	11.2%
	GWh	1.3%	6.0%
Case II: Low Growth	MW	3.9%	6.0%
	GWh	-3.3%	0.3%
Case III: High Growth	MW	7.2%	12.3%
	GWh	1.6%	8.2%

Figure 2 highlights that the load forecasts largely move together in the early part of the study period. Following 2021, divergence in load forecasts can be observed as the difference in retail rates between cases increases. By the end of the study period a variance of 100 MW is observed between the High Growth Case and the Low Growth Case. This further highlights that the impacts of the level of mitigation on retail rates and customer reaction to those impacts remains a significant driver of uncertainty in the resource planning process.

[36] Utility load is the summation of Newfoundland Power and Hydro Rural Requirements.
[37] 2018 peak is not weather adjusted, contributing to the decrease in peak requirements.

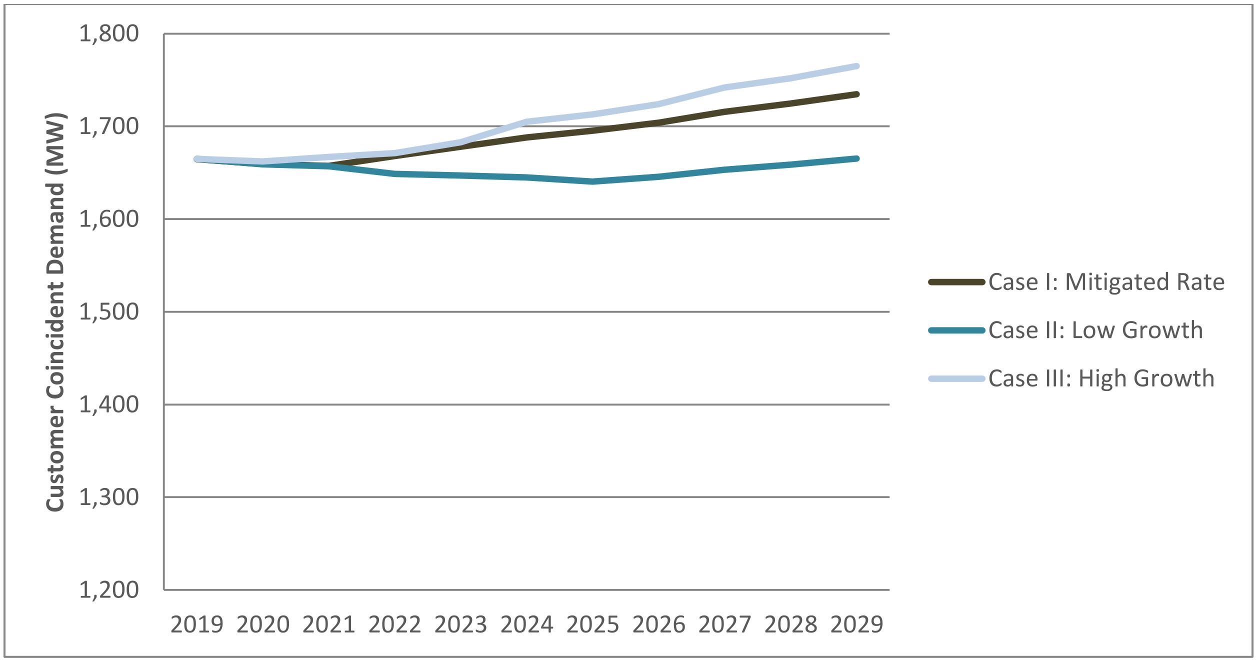

Figure 2: Island Interconnected System Forecast Annual Peak Demand Requirements

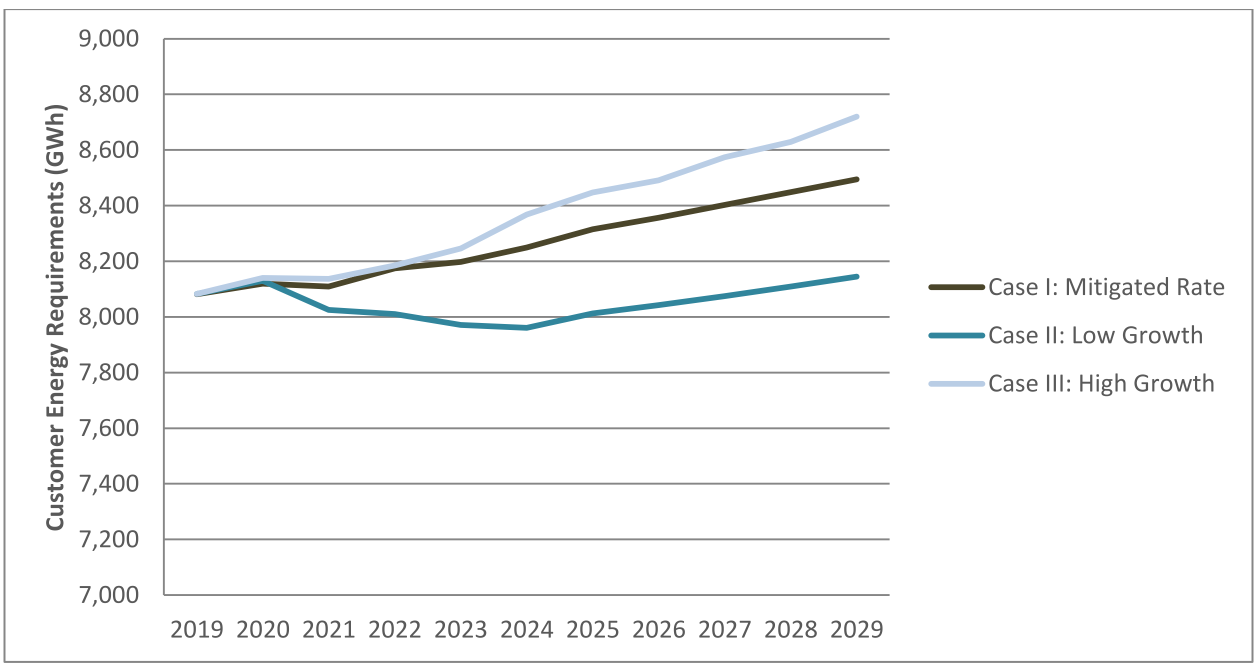

Figure 3 : Island Interconnected System Forecast Annual Energy Requirements

Existing Industrial customer load requirements for the Island Interconnected System for the 2020 through 2029 period reflect the load requirements indicated by the customers. The forecast industrial loads for Cases I and II are essentially flat, while Case III includes modest additional industrial load growth associated with prospective mining sector growth.

6.3 Considered Potential Labrador Load Scenarios

The Labrador Interconnected System load includes the power and energy requirements of the iron ore industry in western Labrador and Hydro's rural customers. The communities include Happy Valley-Goose Bay (including North West River, Sheshatshiu, and Mud Lake), Wabush, Labrador City, and Churchill Falls town site customers.

Table 6 presents the base forecast with a sensitivity case for the total Labrador Interconnected System over the study period. The base forecast reflects Hydro's Rural Load Forecast Spring 2019, which includes existing data centre requirements as well as the loads associated with Wabush mine reactivation by Tacora Resources. A sensitivity case was developed to include additional load requirements for the Department of National Defence ("DND") at 5 Wing Goose Bay.

Table 6: Labrador Utility Electricity Load Growth Summary – 2019 Planning Load Forecast[38,39,40]

		2018–2024[41,42]	2018–2030
Case I: Expected Case	MW	7.4%	8.5%
	GWh	29.1%	30.1%
Case II: Increased Requirements at DND	MW	10.8%	11.9%
	GWh	31.9%	32.9%

[38] Electricity load includes the summation of Happy Valley-Goose Bay (including North West River, Sheshatshiu, and Mud Lake), Wabush, Labrador City, and industrial customers.,

[39] Peaks (MW) are from terminal station delivery points and are coincident with Labrador Interconnected System peak. They are presented on a winter peak basis and include firm requirements for industrial customers.

[40] Electricity loads do not include retails sales for Churchill Falls, which has an annual energy load of 2,400 GWh and a non-coincident peak of 0.3MW.

[41] 2018 peak includes non-firm requirements being taken by IOC and due to metering issues, excludes demand from Muskrat Falls construction site, contributing to the decrease in peak requirements

[42] 2018 energy consumption was impacted by a labour dispute at IOC that resulted in two months of suspended production.

6.4 Discussion of Hydro's Island Interconnected System Winter 2018-19 Peak Demand

Weather conditions across the Island Interconnected System for the first two months of winter 2018–2019 (December and January) were relatively mild as weather conditions during the period were less severe than historically measured average (P50) conditions. The Island Interconnected System experienced the highest electrical demands for the winter of 2018–2019 during a period of cold and windy weather that occurred in the month of February 2019. The maximum peak demand for the Island Interconnected System for winter 2018–2019 occurred during the early evening of February 20, 2019.

Table 7 provides the summarized customer class peak demands as experienced for February 20, 2019 as well as the P50 and P90 expected coincident customer class demands for the winter peak period of 2018-19 as forecast in the spring of 2018.

Table 7: Coincident Customer Peak Demands for Winter 2018–2019 Exclusive of Transmission Losses and Station Service Requirements[43]

	P50 Peak Demand Forecast (MW)	P90 Peak Demand Forecast (MW)	Actual[44]
Utility[45]	1,478	1,539	1,549
Industrial[46]	179	179	157
Island Interconnected System Coincident Customer Demand[47]	1,657	1,718	1,706

The Island Interconnected System coincident customer demand that occurred during the February 20, 2019 system peak was between the P50 forecast and P90 forecast with actual industrial demand less than forecast and actual utility demand higher than the P90 forecast. The observed weather condition can be summarized as colder temperatures than average with wind conditions about average. The weather conditions leading into the Island Interconnected System evening peak were onerous on a temperature basis but not quite as severe as what a P90 wind chill condition would be, based on

[43] Forecast as per "Near-Term Generation Adequacy Report," Newfoundland and Labrador Hydro, May 30, 2018 (rev. 1), originally filed May 22, 2018.
[44] February 20, 2019 actual peak loads for time interval 18:45–19:00; peak occurred at 18:54.
[45] Coincident demand of Newfoundland Power and Hydro Rural retail.
[46] Coincident demand of Island Industrial Customers.
[47] Island Interconnected System customer demand exclusive of transmission losses and station service.

historical weather records. Hydro has reviewed the events surrounding utility demand requirements on the peak day.

Weather conditions on the Avalon Peninsula deteriorated throughout February 20, 2019 with both temperatures and wind chills reaching their lowest points at the time the peak occurred. As temperatures on the Avalon were declining across the day, it could be expected that the performance efficiency of heat pumps used by customers for space heating would have waned, contributing to higher peak demand requirements in the evening period.

Voltage reduction activity by Newfoundland Power would have reduced peak demand requirements during the core morning and evening peak periods. Combined with the prevailing weather conditions on this day, Newfoundland Power's voltage reduction activity may have contributed to a later than typical utility peak that occurred at 19:15.

Based on these observations, the utility demand requirement can be considered significant for the prevailing weather conditions experienced on the peak day.

7.0 Reserve Margin Criteria

7.1 Summary of Proposed Criteria

7.1.1 Planning Reserve Margin

The reserve margin target specifies the reserve margin required to provide the required level of system reliability. In the resource planning process it is used to identify when incremental resources are required to provide adequate system reliability. As detailed in Volume I, Table 8 outlines the recommended capacity planning criteria. These criteria are used to determine when capacity expansion would be required in each considered case. For detailed information on the development of the proposed planning reserve margin, please refer to Volume I, Section 4.1 of the 2018 Filing.

Table 8: Planning Reserve Margin

	Newfoundland and Labrador Interconnected System	Island Interconnected System
LOLE[48] (days/year)	0.1	0.1
Planning Reserve Margin (%)	13%	16%

7.1.2 Operational Reserves

Volume I also detailed the requirement for operational reserves as detailed in Table 9, these requirements are included in Hydro's Resource Planning Model. For detailed discussion of how operational reserve requirements have been modelled in Hydro's Resource Planning model, please refer to Volume I, Section 3.3.1.2 of the 2018 Filing.

Table 9: Operational Reserve Requirements

	Operational Reserve Required (MW)
Ten Minute Reserves	197.5
Thirty Minute Reserves	99
Total	**296.5**

7.2 Additional Case Analysis: Supplying Customers in the Event of the Prolonged Loss of the Labrador-Island Link

In addition to the reasonably expected load cases described previously, Hydro's 2018 Filing presented an additional case for information. With the introduction of the MFGS, a large portion of the generation serving the Island load will be located in Labrador. Therefore, the reliability of the LIL is a key driver of Newfoundland and Labrador Interconnected System reliability. While the robust nature of the design and construction of the LIL, the anticipated asset reliability, and the anticipated required maintenance should result in a high degree of system reliability, Hydro recognizes that the Board and parties wish to better understand the implications associated with a prolonged outage of the LIL. This section also presents system requirements and constraints associated with the operation of the LIL.

[48] Loss of Load Expectation ("LOLE")

7.2.1 Probabilities and Restoration Durations

Liberty's Review and Recommendations

Liberty's Review noted the importance of the LIL to the reliability of the Newfoundland and Labrador Interconnected system in the future. It is therefore imperative for Hydro, stakeholders, and the Board to fully understand the range of service-disruption likelihoods and consequences occasioned by a LIL bipole outage. Liberty's Review suggested that a probability of occurrence and a full range of restoration times, inclusive of travel time and on-site work duration under extreme weather conditions, should be calculated for a range of events.

> ***Liberty's Recommendation #10:***
>
> ***"Hydro should conduct a detailed analysis quantifying the probabilities and restoration durations for a robust range of bipole LIL outages."49***

Liberty further noted that given the importance of the LIL to system reliability, Hydro needs to place high priority on ensuring operational readiness to enable emergency restoration of the line.

> ***Liberty's Recommendation #11:***
>
> ***"Hydro should complete remaining steps to prepare for LIL outages as soon as possible."[50]***

As indicated in Hydro's September 27, 2019 and October 31, 2019 correspondence, Nalcor Energy has continued to develop emergency response planning with respect to the overland portion of the LIL and is compiling a report ("Report 1") that summarizes the activities to date. Report 1 will highlight both operational and engineering requirements with respect to proper emergency response planning for the LIL and various repair philosophies/solutions for consideration. It will also discuss the previous risk analysis and studies completed and identify priority-based recommended work scopes. Further, it will describe the progress to date for specific emergency response planning activities and highlight planned

[49] "Review of Newfoundland and Labrador Hydro's Reliability and Resource Adequacy Study," The Liberty Consulting Group, August 19, 2019, at p. 52.
[50] "Review of Newfoundland and Labrador Hydro's Reliability and Resource Adequacy Study," The Liberty Consulting Group, August 19, 2019, at p. 53.

future activities. It is anticipated that there will be a report issued annually, highlighting any changes in plan and documenting any conducted exercises. The 2019 version of Report 1 is currently in draft, with a final report planned to be filed with the Board on November 29, 2019.

Liberty's Recommendation #1a:[51]

"Hydro should promptly examine the likelihood and the range of consequences of an extended bipole LIL outage under extreme weather circumstances, . . ."[52]

Hydro has engaged a third-party, EFLA Consulting Engineers ("EFLA"), to conduct the engineering review focused on the original design criteria and the structural capacity of the as-built design based on site-specific details and potential extreme weather conditions. Hydro has also engaged Halder & Associates, a third-party consultant with extensive knowledge of reliability and operating experience, which is intimately familiar with Hydro's system. Halder & Associates has been engaged to review and provide feedback on the findings presented by EFLA. A final report ("Report 2") describing the analysis undertaken and study findings will then be filed with the Board. Table 10 outlines the anticipated timelines for completion of the work for Report 2.

Table 10: Schedule for Completion of Report 2

Activity	Party Responsible	Anticipated Completion Date
Computer-based modelling and detailed analysis	EFLA	November 15, 2019
Study findings and draft report issued for review	EFLA	December 6, 2019
Review of study finding and draft report	Halder & Associates	January 17, 2020
Revised analysis, based on Halder & Associates' review	EFLA	January 31, 2020
Final report filed with Board	Hydro	February 28, 2020

To the extent that the findings of either Report 1 or Report 2 require additional modelling scenarios to be undertaken in PLEXOS, Hydro will begin such studies immediately upon receipt of the final reports

[51] Hydro has divided recommendation 1 from Liberty's Review into two separate parts, designated a and b, to ensure the question has been fully addressed.
[52] "Review of Newfoundland and Labrador Hydro's Reliability and Resource Adequacy Study," The Liberty Consulting Group, August 19, 2019 at p. 21.

from the engaged parties. The effort necessary to model results will be assessed at that time and Hydro will provide a schedule to the Board indicating when Hydro's will file it's report containing the results of its analysis ("Report 3") will be filed. Hydro estimates that such work could take up to three months to complete; however, the amount of time required to complete the modelling exercises will vary based on the complexity of implementing such scenarios in Hydro's PLEXOS model and the computational requirements of the scenarios being considered. Hydro will provide Report 3 to the Board as an addendum to this report.

7.2.2 Regulating Reserve in the Event of the Loss of the Bipole

As presented in "TP-TN-068 - Application of Emergency Transmission Planning Criteria for a LIL Bipole Outage" ("TP-TN-068"),[53] Hydro maintains a minimum reserve of 70 MW within the island system under contingency operations to provide for acceptable frequency regulation. In the event of a LIL bipole outage, frequency regulation would be provided by island generators. For generation planning purposes, 70 MW of available Island Interconnected System capacity shall therefore be assumed to be reserved for frequency regulation.

7.2.3 Voltage Instability for Loss of Pole When Island Load Exceeds 1600 MW

As part of its ongoing operational studies, Hydro has investigated transmission system operating limits when the LIL bipole is in service. In the Stage 4D Study,[54] it was found that at Island Interconnected System demand levels of 1600 MW or greater, it becomes necessary to dispatch Avalon generation to avoid voltage collapse in the event of a trip of the LIL bipole. Results indicate that the voltage collapse is not a function of the pre-event LIL power flow or the 230 kV power flow to the Avalon Peninsula, but rather it is a function of the total power flow over the 230 kV corridor following the LIL trip. This is due to the lack of dynamic reactive support to withstand such significant power flows in the Bay d'Espoir to Soldier's Pond corridor. As a result of this requirement, generation on the Avalon Peninsula must be placed in service in accordance with the parameters provided in Table 11 when Island Interconnected System demand exceeds 1600 MW.

[53] Filed with the Board on July 31, 2019.
[54] "Stage 4D LIL Bipole: Transition to High Power Operation," TransGrid Solutions, September 25, 2019, filed with the Board September 30, 2019.

Table 11: Avalon Thermal Generation Requirement when Island Interconnected System Demand Exceeds 1600 MW

Island Interconnected System Demand (MW)	Avalon Generation (MW)
>1830	123.5
1700–1830	90–110
1650–1700	60–70
1600–1650	30

7.2.4 Exposure for Underfrequency Load Shedding with Monopole Loading in Event of Forced Pole Outage

The LIL bipole is rated for 900 MW and each pole has a nominal rating of 450 MW with a 10-minute overload capability of 2 pu (or 900 MW) and a continuous overload rating of 1.5 pu (675 MW). In accordance with Transmission Planning Criteria, the loss of a pole shall not result in underfrequency load shedding under normal operation. As presented in TP-TN-068, criteria are not defined when the LIL bipole is out of service.

The TP-TN-068 technical note included an assessment of system performance for the existing system and review of the application of Transmission Planning Criteria during a LIL bipole outage scenario. Violations to Transmission Planning Criteria and remedial actions were identified and recommendations of appropriate Transmission Planning Criteria for a LIL bipole outage scenario were provided.

As part of the assessment of resource adequacy, consideration must also be given to planning criteria to be applied in the event of a LIL pole outage. In the event of an extended pole outage, the healthy pole could be loaded up to 675 MW continuously. However, it is noted that a pole trip while in this mode of operation would result in underfrequency load shedding. For the purposes of this investigation, this risk of controlled load shedding is deemed to be acceptable and is preferable to the more extensive customer outages that would result from limiting the capacity of the LIL monopole to a range of values less than 200 MW. The limits for this mode of operation will be established as part of the TransGrid Solutions Stage 4E Study. On this basis, the capacity of the LIL monopole is assumed to be fixed at 675 MW.

7.2.5 Transmission System Capacity in the Event of a LIL Bipole Outage

The TP-TN-068 technical note included the development of base cases to determine maximum customer loads that can be supported during a LIL bipole outage. With no incremental generation installed within the Island Interconnected System and with no Maritime Link imports, the base cases are summarized as follows:

- Total Island System Capacity ≃ 1400 MW, representing total Island generation;
- A regulating reserve of 70 MW is maintained within the Island system;[55]
- An Island Interconnected System demand of approximately 1330 MW can be supported in this case; and
- The sum of station service and transmission losses in this case is approximately 70 MW meaning that customer load of 1260 MW can therefore be supported in this case.

7.2.6 Assessment of the LIL Bipole Outage Scenario

To inform a risk-based analysis of such implications, in addition to modelling the LIL with its anticipated availability, an extended outage case was also modelled. The extended outage case models a scenario where the LIL is unavailable for three weeks during January (i.e., during peak) to quantify the resultant system reliability and identify the costs associated with providing incremental generation to reduce the loss of load probability. The unavailability is intended to simulate an icing situation that causes tower collapse in a remote segment of the transmission line.

As per Section 7.2.5, a total customer load of approximately 1260 MW can be supplied in the event of a LIL bipole outage. To provide a visual example, Figure 4 shows the exposure for unserved energy if the outage were to occur on the peak day in the test year.[56] This exposure will continue to increase as load on the Avalon Peninsula increases.

[55] As defined in Section 7.2.2
[56] Based on a P50 peak demand forecast.

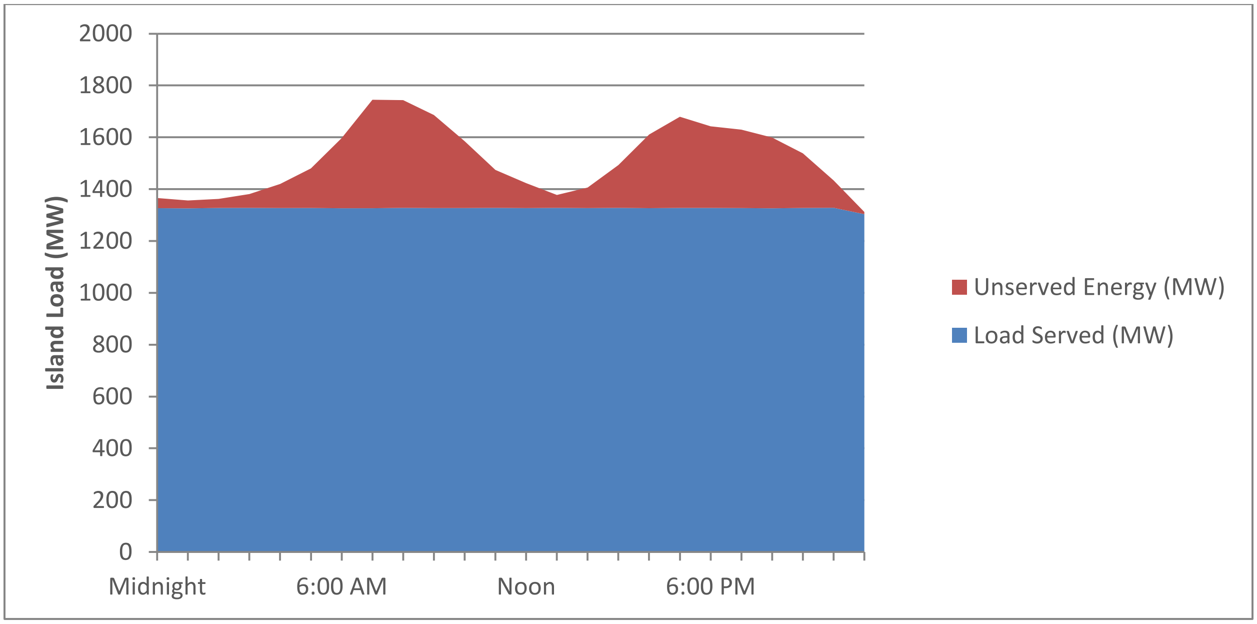

Figure 4: Forecast Shortfall on Peak Day with the LIL unavailable

Figure 5 and Figure 6 provide an indication of the shortfall of supply if the interruption were to occur for three weeks at the period of highest annual demand requirements.

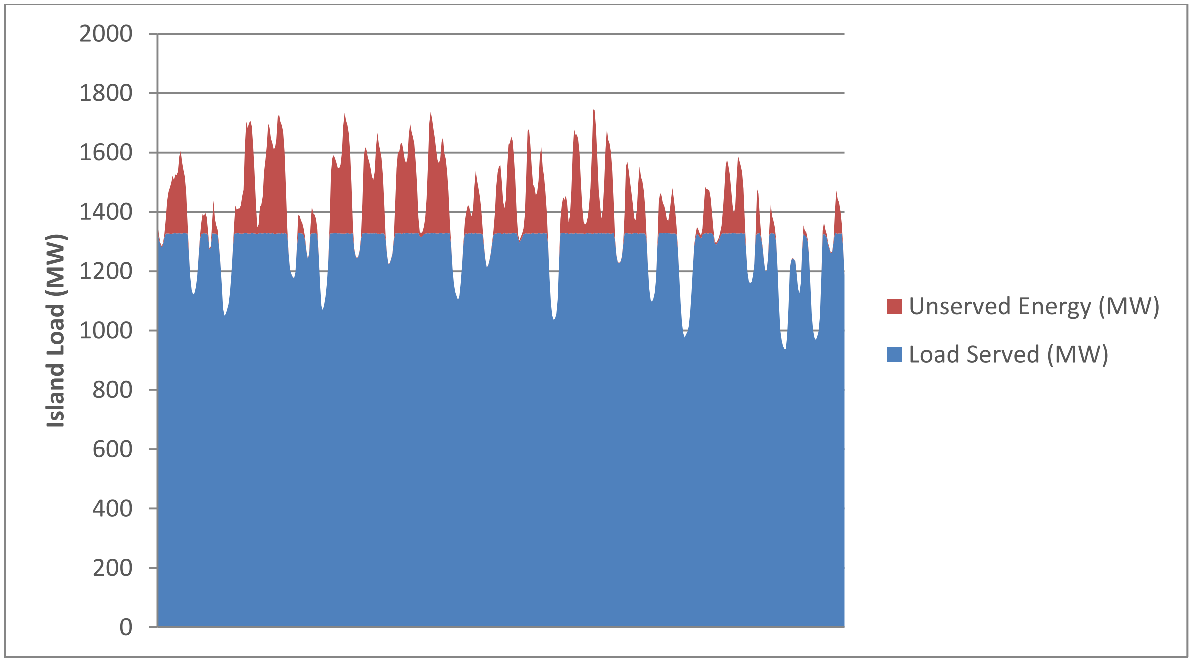

Figure 5: Forecast Daily Shortfall with LIL Unavailable Through a Three-week Period

Figure 5 highlights that if a three-week outage were to occur at time of system peak, varying degrees of rotating outages could be expected for the majority of the period. Figure 5 also shows that there would likely be days with minimal exposure to loss of load events. Figure 6 plots the load duration curve for the same period.

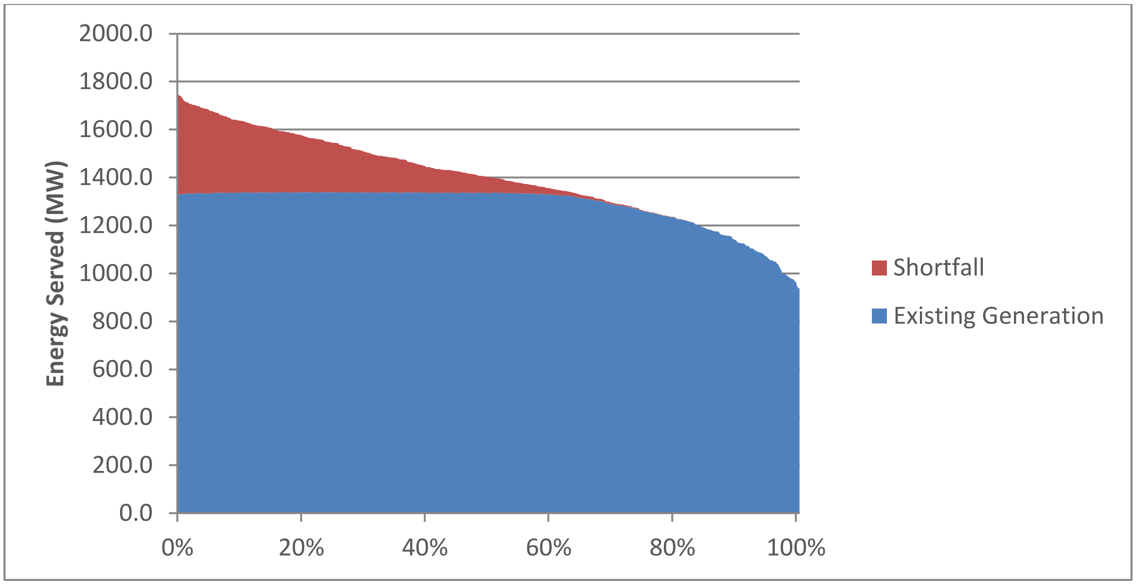

Figure 6: Forecast Shortfall with LIL Unavailable Through a Three-week Period

7.2.7 Impact of Incremental Generation

Hydro has performed analysis to assess the impact of incremental generation on the customer load interruptions presented in the previous section.

Incremental generating sources included as part of the analysis include:

- Up to six 58.5 MW GTs on the Avalon Peninsula; and
- Addition of 154 MW Bay d'Espoir Unit 8.

The changes in shortfall made possible with the addition of GTs can be observed in Figure 7 through Figure 9. Results are further summarized in Table 12.

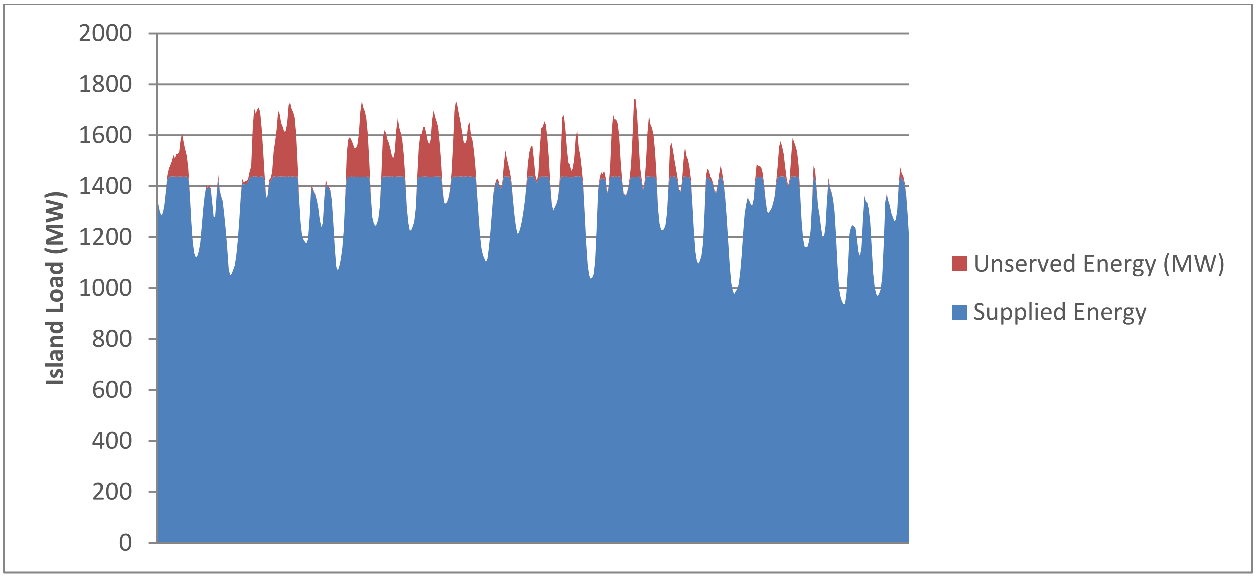

Figure 7: Change in Shortfall with Addition of Two Gas Turbines

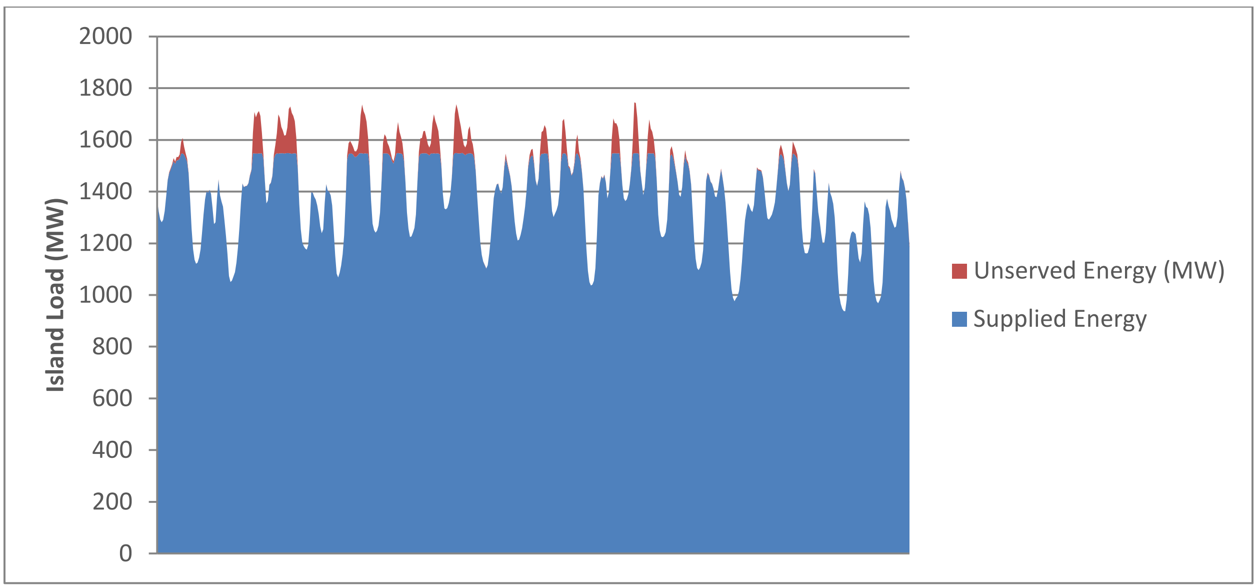

Figure 8: Change in Shortfall with Addition of Four Gas Turbines

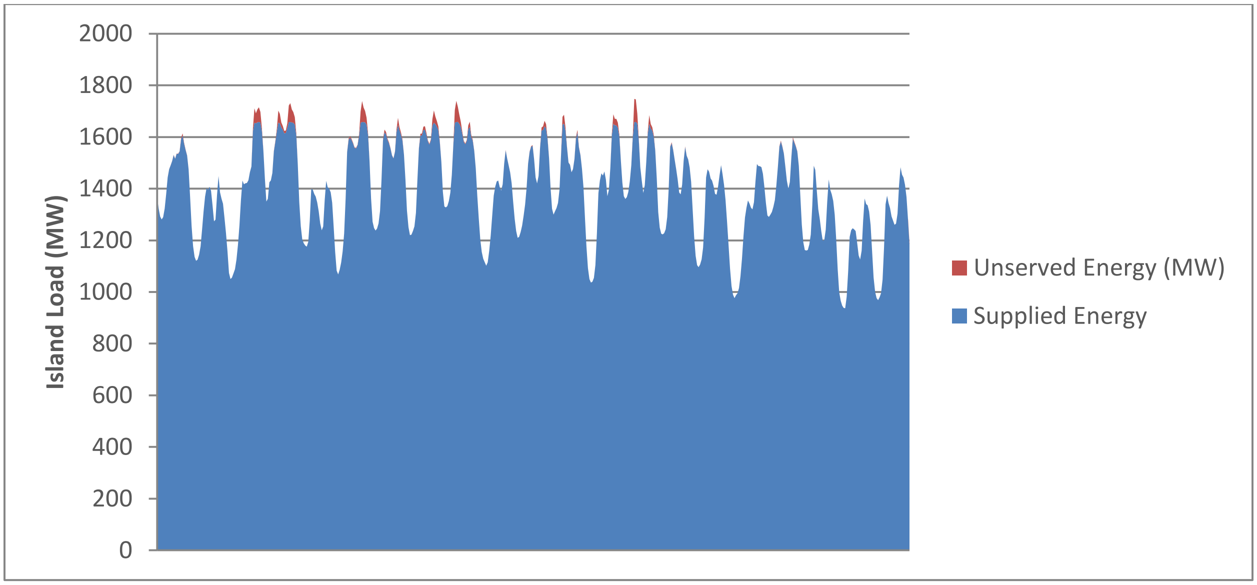

Figure 9: Change in Shortfall with Addition of Six Gas Turbines

Table 12: Summary of Anticipated Shortfalls with Incremental Generation

Case	EUE[57] (GWh)	Hours of Generation Shortfall
No Incremental Generation	56.1	319
+ 2 GTs	27.7	208
+4 GTs	10.4	117
+6 GTs	2.3	40

Similar results are observed when adding Bay d'Espoir Unit 8 in combination with GTs, as seen in Figure 10 through Figure 12 and summarized in Table 13.

[57] The expected amount of demand that is unserved per year due to demand exceeding generating capacity.

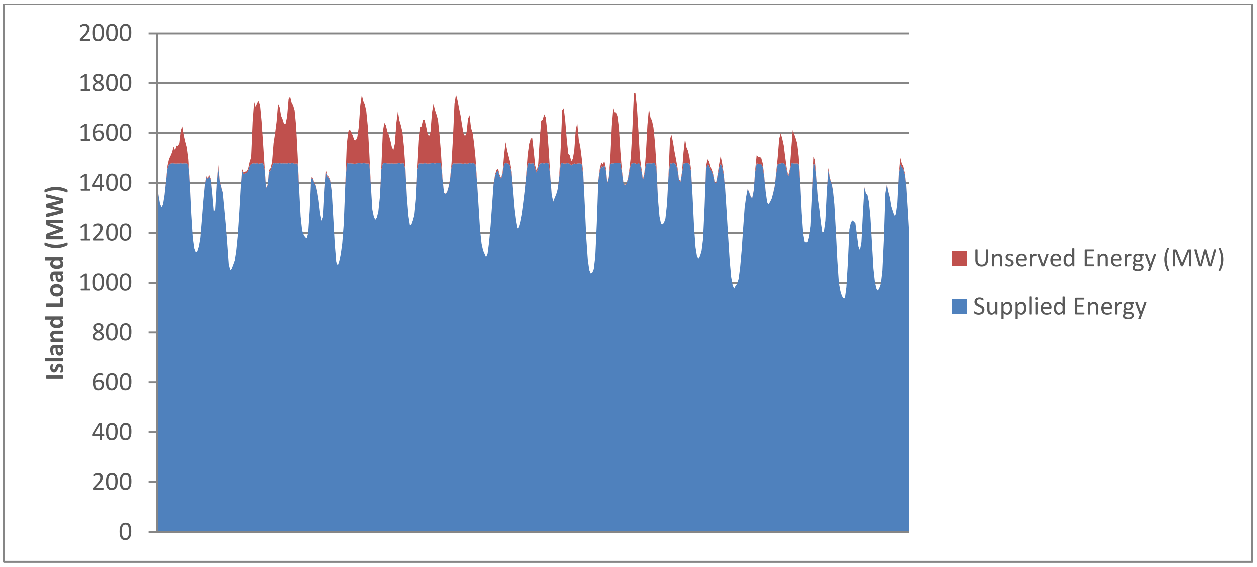

Figure 10: Change in Shortfall with Addition of Bay d'Espoir Unit 8

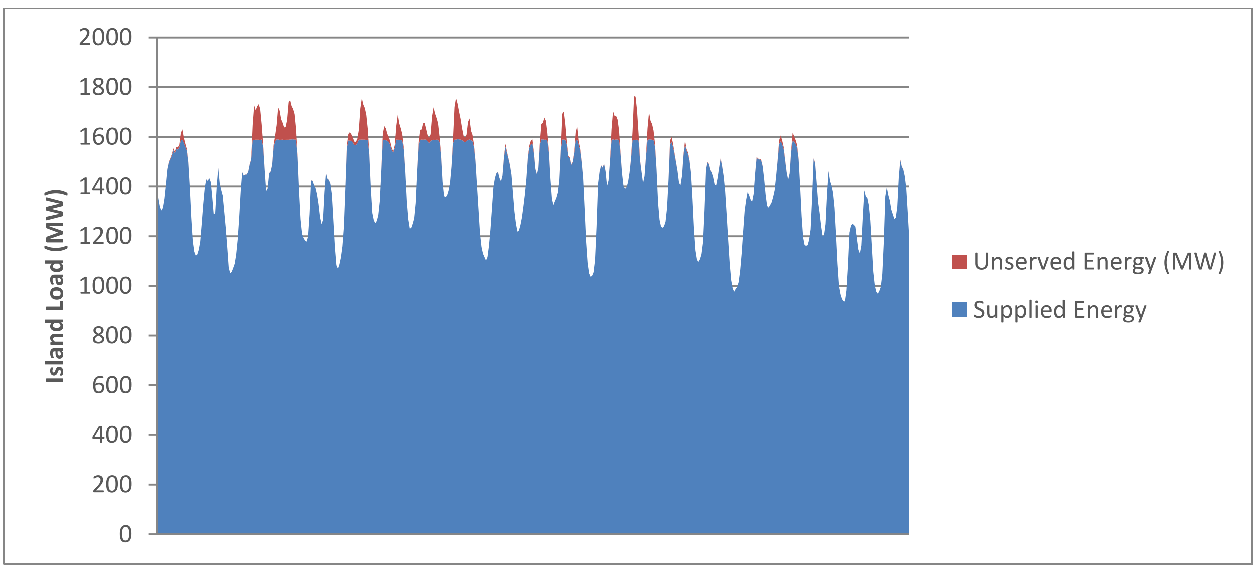

Figure 11: Change in Shortfall with Addition of Bay d'Espoir Unit 8 and Two Gas Turbines

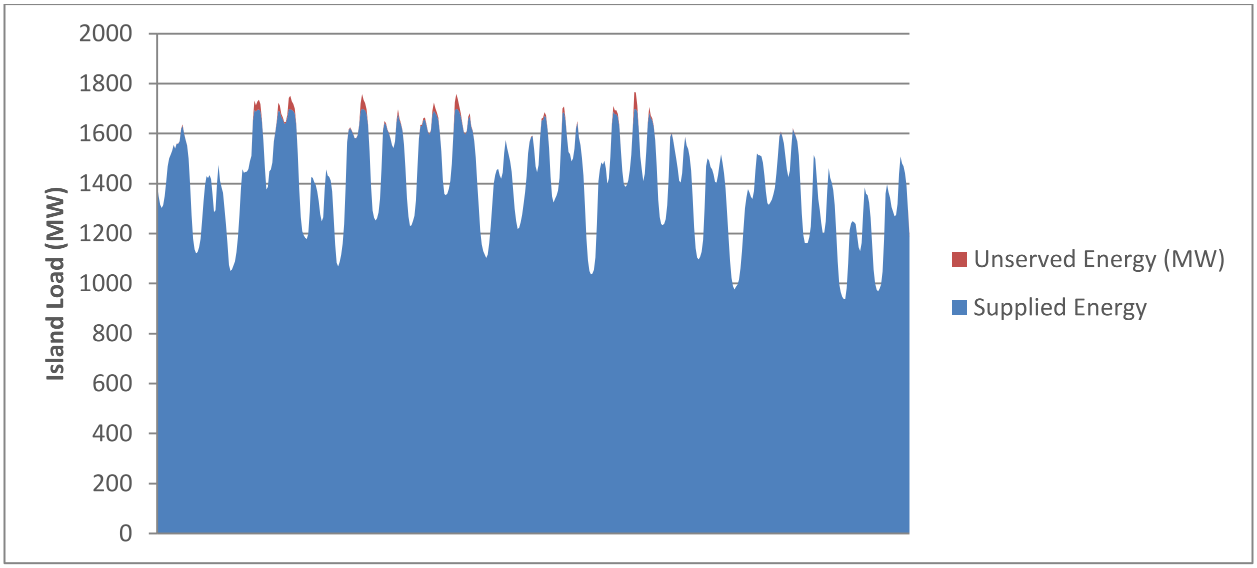

Figure 12: Change in Shortfall with Addition of Bay d'Espoir Unit 8 and Four Gas Turbines

Table 13: Summary of Anticipated Shortfalls with Incremental Generation

Case	EUE(GWh)	Hours of Generation Shortfall
No Incremental Generation	56.1	319
+ Bay d'Espoir Unit 8	23.8	193
+ Bay d'Espoir Unit 8 and 2 GTs	8.2	102
+ Bay d'Espoir Unit 8 and 4 GTs	1.3	29

When compared to the results in the 2018 Filing, the shortfalls observed in Figure 5 and Figure 6, which have no mitigating efforts, are more severe primarily due to three factors:

1) The analysis in the 2019 Update was completed on the 2026 Test Year, while the 2018 Filing was completed for 2022, which was selected as it is the first winter operating season following the scheduled retirement of Holyrood TGS. There is an increase of 45 MW in peak demand between the cases.

2) The analysis in the 2019 Update includes a 70 MW minimum operating level as described in Section 7.2.2

3) The analysis in the 2019 Update was done probabilistically and includes load forecast uncertainty and unit outages.

Hydro's analysis shows the extent to which incremental resources help to mitigate the potential for unserved energy in the event of the prolonged loss of the bipole. The addition of six 66 MW GTs or Bay d'Espoir Unit 8 and four 66 MW GTs would be sufficient to limit outages to only the highest peak hours, as shown in Figure 9 and Figure 12.

It is important to note that these results represent a very low probability, high consequence event. The likelihood of the loss of a bipole for an extended period is very low by design and it is less likely again that this loss would occur during the highest load period of the year. Once available, Reports 1 and 2, as described in Section 7.2.1, will provide additional information of the probabilities, restoration times, and the structural capacity of the as-built design. These reports should provide additional clarity on the potential severity and likelihood of such an event. This will be complemented by Hydro's VOLL analysis, which should provide insight regarding the cost sensitivity of provincial electricity customers to outages. Hydro remains committed to working with the Board and stakeholders to contemplate how this scenario should be incorporated into Hydro's planning process, particularly in balancing cost and reliability.

7.2.8 Transmission Considerations for Incremental Generation

The TP-TN-068 technical note included a review of violations to Transmission Planning Criteria in the event of a LIL bipole outage. For the case with no incremental generation it was found that violations included a thermal overload of TL 201 in the event of an outage to TL 217.

The addition of GT generation on the Avalon Peninsula would mitigate the violation listed above and reduce the amount of load shedding that would be required proportional to the incremental generation.

The TP-TN-068 technical note also included analysis to assess violations to Transmission Planning Criteria in the event of a LIL bipole outage if an incremental off-Avalon supply of 300 MW were available.[58] Violations in this case were identified as follows:

- Thermal overload of TL 201 in the event of an outage to TL 217;
- Thermal overload of TL 217 in the event of an outage to TL 201;

[58] For the TP-TN-068 Analysis, this supply was assumed to be made available as import over the Maritime Link.

- Transient undervoltage violations for three-phase fault at Sunnyside; and
- While not a violation, instability occurs for a three-phase fault at Bay d'Espoir, followed by the tripping of TL 202, TL 206, or TL 267.

It is noted that the addition of generation off the Avalon Peninsula such as Bay d'Espoir Unit 8 at a rating of 154 MW would result in violations similar to those listed above. These violations would be exacerbated in the event that this unit were combined with Maritime Link imports that resulted in a total incremental off-Avalon supply in excess of 300 MW.

A detailed transmission system reliability assessment associated with incremental generation alternatives would be required to appropriately assess the impact of the same. Hydro recommends that once there is specificity relating to the requirement for incremental generation on the Island Interconnected System, a more detailed Transmission Planning Assessment may be performed that would include the following:

- A review of transmission system performance for solutions involving incremental generation on the Avalon Peninsula;
- An analysis to determine if transmission system reinforcement is required to ensure acceptable system performance for solutions involving incremental generation off the Avalon Peninsula; and
- A review of Emergency Transmission Planning Criteria for a LIL Bipole Outage for suitability as an acceptable long term solution.

7.3 Energy Criteria

The proposed energy criterion is that there must be adequate firm generation on the system to supply firm load on an annual basis.[59]

[59] Firm capability for the hydroelectric resources is the firm energy capability of those resources under the most adverse three-year sequence of reservoir inflows occurring within the historical record. Firm capability for the thermal resources (Holyrood TGS) is based on energy capability adjusted for maintenance and forced outages.

Energy:

The Newfoundland and Labrador Interconnected System should have sufficient generating capacity to supply all of its firm energy requirements with firm system capability.

The ability to meet energy requirements is continually evaluated in consideration of historical inflow sequences and future customer and contracted requirements. The Newfoundland and Labrador Interconnected System does not violate this criterion through the study period.

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

Currently, there are no forecast violations of the proposed energy criteria. If in future a potential for violation were identified, the opportunity to procure firm imports to supplement native supply could be considered and the planning criteria modified appropriately. Other jurisdictions do consider firm imports from an energy planning perspective.

8.0 Results and Recommendations

The results of the reserve margin-based analysis across all 12 scenarios indicate that the requirement for additional resources is capacity driven and most sensitive to retail electricity rate, economic growth, and explicit use of the P90 weather variable in evaluating the requirement for incremental resources.

Six of the twelve cases considered require additional resources inside the ten-year study period.

A summary of the incremental resource additions for these cases are included in Table 14. The remaining six cases considered require no additional resources through the study period. The full results for all 12 cases considered are included as Attachment 2 to this volume.

Table 14: Scenarios requiring Incremental Resource Additions

Island Load Case	P50 vs P90	Labrador Load Case	Year of Resource Requirements
Case I: Mitigated Rate	P90	Labrador Expected	2026
		Labrador Industrial Growth	2025
Case III: High Growth	P50	Labrador Expected	2029
		Labrador Industrial Growth	2028
	P90	Labrador Expected	2024
		Labrador Industrial Growth	2024

Currently, Bay d'Espoir Unit 8 is being selected by the model as the least-cost option of those explicitly modelled in all scenarios requiring additional resources. Hydro remains committed to better understanding the roles that CDM, rate structure, and alternative technologies such as battery storage, can play in the Newfoundland and Labrador Interconnected System. The ability to use alternative resources to supply the Newfoundland and Labrador Interconnected System will depend on the timeframe in which decisions on investment are required. As identified in Table 13, Hydro could require incremental resources as early as 2024 in the case with the highest forecast demand requirements; that is the case which considers high economic growth on the Island, combined with the proposed rate mitigation target, and incremental industrial demand in Labrador.

Similar to results from Hydro's 2018 Filing, use of the P90 peak demand forecast in evaluating the requirement for incremental resources advances investment substantially from the late 2020s. Hydro maintains that basing supply planning decisions on a P50 peak demand forecast, while continuing to assess and report to the Board on forecast exposure under the P90 peak demand forecast, balances system reliability and investment cost at this time. Further, by embedding load forecast uncertainty in the determination of planning reserve margin increases the conservatism embedded in forecast modelling compared to modelling only the P50 and P90 discretely. Additionally, given that Hydro is recommending planning decisions be made on the more conservative LOLE of 0.1, there is incremental conservatism included in Hydro's planning process as compared to that previously conducted. Use of the

P50 peak demand forecast for supply planning would require additional resources in two cases towards the end of the ten-year study period.

As discussed in Section 7.2 the prolonged unavailability of the LIL is considered a low-probability, high-consequence event. In this update, Hydro has provided additional information for the consideration of the Board and stakeholders on the expected shortfall if the LIL were to be out of service for three weeks at time of peak demand and the amount by which the shortfall can be reduced with incremental resources. Hydro remains committed to working with the Board and stakeholders to contemplate how this scenario should be incorporated into Hydro's planning process, particularly in balancing cost and reliability.

8.1 Action Plan

Hydro looks forward to participating in the regulatory process to further inform parties on the results of both the 2018 Filing and the 2019 Update and working with stakeholders and the Board to determine which scenarios should drive capital investment. Long-Term planning takes a conservative approach, and Hydro will ensure system needs are well understood and all options have been carefully considered before recommending significant investments. Further optimization of results will be undertaken, as required to support decision-making, and also as part of the annual planning exercise.

Through 2020 Hydro commits to:

- Working with the Board and stakeholders to continue review of Hydro's 2018 Filing and the 2019 Update.
- Complete full condition assessment of all major systems components of the Holyrood TGS units and plant, including internal inspections to deliver a report to the Board in January 2021.
- Provide reports on emergency response planning and the review focused on the original design criteria and the structural capacity of the as-built design based on site-specific details and potential extreme weather conditions for the LIL.
- Execute a stakeholder engagement process to address VOLL.
- Execute a hydrology study to assess the impact of Bay d'Espoir Unit 8 on the Bay d'Espoir reservoir system.

In the long-term, by conducting this analysis annually, the impact of any changes in key inputs that materialize over the course of the year will be included in Hydro's analysis in a timely manner.

Appendix A

Assessment of Requirements to Enable Short-Term Extension of Holyrood Thermal Generating Station

Introduction

As indicated in Hydro's correspondence to the Board dated October 31, 2019, based on the established schedule for power delivery from the Muskrat Falls project, Holyrood TGS is expected to have all three units available for operation at full capacity until March 31, 2021. Beyond that date, Unit 3 at Holyrood TGS will continue to operate as a synchronous condenser, while Units 1 and 2 are scheduled to be shut down and decommissioned.

The existing capital and operating and maintenance plans for the Holyrood TGS have been developed based on this schedule. The existing capital plan includes projects to facilitate steam generation from all units to March 31, 2021. The plan also includes projects for the conversion of Unit 3 to a dedicated synchronous condensing unit and projects required to support synchronous condensing operation into the future. The operating and maintenance plans, likewise, are constructed around the staffing and maintenance required to operate Holyrood TGS as a fully capable generating facility until March 31, 2021 and a single unit synchronous condensing facility beyond that date.

The current delays in the reliable supply of energy from the Muskrat Falls project makes it prudent to identify any changes to existing capital and operating and maintenance plans required to enable the Holyrood TGS to continue to be available to reliably supply customers while the project assets are being placed in-service and proven reliable. This report provides details with respect to contingency plans to enable short-term continued operation of the Holyrood TGS beyond April 2021 (Phase One).

While investigation is ongoing and Hydro is not recommending proceeding with Phase One at this time, the details are provided to further inform the discussion regarding the provision of reliable supply for customers. By the end of 2019, Hydro will be better informed to decide whether extended operation of Holyrood TGS is required beyond March 31, 2021. At that time, Hydro expects to have more clarity surrounding key milestones associated with the Muskrat Falls project. In January 2020 Hydro will provide the Board with its decision regarding a short-term extension (i.e. one to two years).

Phase One

In this phase, all three Holyrood TGS units will be able to operate reliably, whether online in generation mode or in hot-standby mode. Further, when operating in hot standby mode, units must be able to be recalled from standby to provide generation to the grid within four to eight hours. This mode of operation is currently planned to April 2021 but could be extended by one or two years to March 31, 2022 or March 31, 2023 with additional investment. If this period were extended, it is expected that the overall energy produced by these units would be reduced considerably from recent years due to expected availability of energy over the LIL. Operationally, the Holyrood TGS units could be either online or in hot-standby as a backup for the loss of the LIL bipole, depending on the reliability of assets and system requirements. Hydro expects that when online, units will operate primarily at minimum loading.

The following provides information on required capital execution, supplemental capital plans, and operation and maintenance ("O&M") activities including projected budgets and environmental considerations. Also included is information on activities associated with a planned major system review and life extension requirements study.

Assessment of Capital Work

Capital work currently identified, as well as that required to implement Phase One of Hydro's contingency plan is detailed in Tables 1 through 4 and has been categorized using three general classifications of projects:

- Type 1: Sustaining capital work that is not dependent on end of steam operation;[60]
- Type 2: Capital work required to repurpose Holyrood TGS from a three-unit generating facility to a single-unit synchronous condensing plant;[61] and
- Type 3: Identified supplemental capital work required for safe and reliable operation of the steam generating equipment for an additional two years to March 31, 2023.

[60] There is no change from the current plan for these projects.
[61] It is assumed that this capital work would be deferred to occur once the Holyrood TGS has been deemed not to be required for steam generation.

Table A-1: 2020 and 2021 Capital Projects from Current Capital Plan (Types 1 and 2 - Sustaining and Repurposing Projects)

Year	Project	Classification
2020	Replace existing Stage 1 4160 V ac Breakers as Required (Defer to 2022)	Type 2
	Upgrade UPS[62] 1 & 2	Type 2
	Replace Stage II Electrical Distribution Equipment (Defer to 2021)	Type 2
	Rewind Unit 3 Generator Stator	Type 1
	Upgrade UPS 3 and 4	Type 1
	Install Plant Heating System	Type 2
	Install New Lube Oil / Seal Oil Systems Unit 3 (Defer to 2022)	Type 2
	Upgrade Waste Water Basin Building	Type 1
	Thermal In Service Failures	Type 1
	Upgrade Cooling Water System Wet Well Stop Log Unit 3 (Defer to 2023 - add to year 1 of Pumphouse Refurbishment)	Type 2
2021	Replace One of North or South Instrument Air Receiver Systems Unit 3	Type 1
	Inspect Stacks	Type 1
	Upgrade Property Fencing	Type 1

Additional projects required to enable extension of operations at Holyrood TGS for one and two years are included in Tables 2 through 4 (Type 3). Several of these projects are expensive, long cycle overhauls on turbine and generator equipment that trigger near the end of steam generation. Timing of these overhauls is based on technical recommendations and operational experience, and they have been proven to enable safe, reliable operation. Hydro has included a review of these overhauls inside an initiated study on Phase One, anticipated to be completed in Quarter 1 2020. The intent is to determine if the full extent of the overhauls is required in light of expectations without unreasonably increasing safety or reliability risk.

Also of note, this list of projects assumes that Hydro will be successful in extending environmental certification of bunker storage tanks 2, 3 and 4. Hydro is currently working with the environmental regulator, the Provincial Department of Municipal Affairs and Environment ("MAE"), towards this and

[62] Uninterruptible Power Supply ("UPS")

has submitted reports to them in support of approval. Holyrood TGS production is expected to be substantially lower than in the recent past with the LIL being in service, three tanks are sufficient to support the operation contemplated in Phase One. Bunker storage tank 1 is not suitable for continued operation past 2021.

Table A-2: Critical Projects for Phase 1 extended Holyrood TGS Generation Capability to March 31, 2022

Item	Project	Estimate	Year	Comments
1	Refurbish Unit 3 Boiler Feed Pump West	350,000	2020	Six-year scheduled overhaul. This was originally scheduled for 2019, deferred based on condition.
2	Condition Assessment and Misc. Upgrades (Boilers and High Energy Piping)	3,000,000	2020	This will be required for each year of extension. This project entails detailed inspection, refurbishment and replacement of critical boiler pressure components and is a must do from a safety perspective.
3	Condition Assessment and Misc. Upgrades (Boilers and High Energy Piping)	3,000,000	2021	This will be required for each year of extension. This project entails detailed inspection, refurbishment and replacement of critical boiler pressure components and is a must do from a safety perspective.
	Total	**6,350,000**		

Table A-3: Additional Triggered Projects for Phase 1 Extended Holyrood TGS Generation Capability to March 31, 2022[63]

Item	Project	Estimate	Year	Comments
4	Overhaul Unit 2 Turbine Valves	3,300,000	2020	Three-year scheduled overhaul. This three-year interval was developed by Hydro with consultation from Hartford Steam Boiler, and was endorsed by OEM (GE), FM Global, and AMEC. Consistent with industry practice.
5	Overhaul Unit 2 Generator	1,250,000	2020	Six-year scheduled overhaul. This six-year interval was developed by Hydro with consultation from Hartford Steam Boiler, and was endorsed by OEM (GE), FM Global and AMEC. Consistent with industry practice. This project will be assessed for optimization in 2020 and adjusted if appropriate.
6	Major Overhaul Unit 1 Turbine	6,800,000	2021	Nine-year scheduled overhaul. This nine-year interval was developed by Hydro with consultation from Hartford Steam Boiler, and was endorsed by OEM (GE), FM Global and AMEC. Consistent with industry practice. This project will be assessed for

[63] Further condition assessment is planned for completion in the first quarter of 2020 to confirm and optimize.

				optimization in 2020 and adjusted if appropriate.
	Total	**11,350,000**		

Table A-4: Additional Triggered Projects for Phase One Extended Holyrood TGS Generation Capability to March 31, 2023[64]

Item	Project	Estimate	Year	Comments
7	Overhaul Unit 3 Turbine Valves	3,400,000	2022	Three-year scheduled overhaul. This project may not be required pending availability and reliability of LIL and Muskrat Falls and production requirements from the Holyrood TGS.
	Total	**3,400,000**		

Operating and Maintenance Plans

O&M Budgets

End of Steam March 31, 2021

The current annual operating budget for Holyrood TGS is $24M. Under current plan, it is expected that this budget would remain similar for 2020, with a slight reduction in System Equipment and Maintenance (“SEM”) costs due to the pending end of steam generation. In 2021 and beyond, the annual operating budget would be considerably lower due to reduced staff and reduced maintenance.

Phase One Extended Operation Beyond 2021:

It is expected that O&M costs for safe, reliable operation of the plant as contemplated in Phase One, would require similar maintenance programs and costs as current state in 2019. If the plant operation were to be extended to 2022 or 2023 then the O&M budget for 2020 and 2021 would be similar to 2019. There could be reductions commencing in 2022, pending reduction of energy output needs from the steam generating assets. Associated human resource plans, service contracts and fuel contracts would need to be extended, typical of 2019. Also Holyrood TGS operates under an Environmental Certificate of Approval to Operate, issued by the Provincial Department of MAE, with the current

[64] Further study is planned for 2021 to confirm and optimize.

Certificate of Approval to Operate expiring in August 2021. If Phase One of the contingency plan is implemented, a new or revised certificate will be required to operate beyond August 2021.

Depending on requirements for extended generation, additional upgrades may be required including a landfill extension and upgrades to ambient air monitoring systems, MET Station, CEMS (continuous emissions monitoring), and the wastewater basin building. With the exception of the landfill extension, which would be considered an operating expense, these items are on or will be added to the capital plan as necessary.

Condition Assessment of Major Systems to Support Indefinite Operation (Phase Two)

Hydro is preparing to conduct a condition assessment of major systems and life extension study for the Holyrood TGS in 2020. An application for supplemental capital expenditures is being developed to engage a contractor with extensive boiler experience to complete this work. Upon approval of the capital application, Hydro will issue an RFP to select and engage a contractor. Hydro anticipates the study will require approximately ten months to complete. This accounts for the staggering of annual maintenance outages on the units allowing for physical access to key equipment which is required for off-line detailed inspections and assessments. An anticipated schedule for this review was provided in Hydro’s letter to the Board on October 31, 2019 and is provided below.

Activity	Anticipated Completion Date
Supplemental application for capital expenditure to complete major system review and life extension study for the Holyrood TGS filed with the Board	December 16, 2019
Issuance of RFP, pending approval of the supplemental application	December 31, 2019
Awarding of RFP	On or before February 28, 2020
Completion of work related to major system review and life extension study including final report	November 30, 2020
Results of the major system review and life extension study filed with the Board	January 29, 2021

As outlined in Hydro’s October 31 correspondence, this study will include a full condition assessment of major systems, which will be performed during the annual unit outages. Hydro has begun to prepare a list of items that will require assessment and a draft list is provided below.

- Boiler Steam Drum – full internals removal and detailed non-destructive examination – all units;
- Forced Draft Fan internal assessments – all units;
- Air Heater internal assessments – all units;
- Deaerator Unit 1 and Unit 3 – full removal of internals for FAC inspection (Unit 2 was done recently);
- Detailed review of 2020 boiler tube thickness surveys – all units;
- Unit 3 Reheater Tube Bends – detailed assessment of thinned tubes;
- Condenser waterboxes - detailed assessment - all units;
- Unit 3 boiler windbox attachment to corner waterwall tubes;
- Unit 1 turbine bearing vibrations – assess and provide recommendations on how to improve, particularly on start-up;
- Unit 1 and Unit 2 generator stator / rotor windings – condition assessment;
- Mark V Turbine Governor for Unit 1 and Unit 2 – assessment and recommendations;
- Review of steam turbine and valve condition – all units;
- Last stage blades in all turbines – assessment and recommendations;
- Unit 3 turbine steam chest – assessment and recommendations;
- Main Steam Inlet elbows to Upper Control Valves – Unit 1 and Unit 2 – remaining life assessment (not an issue for Unit 3);
- Turbine hydraulic systems review – Unit 1 and Unit 2;
- Circulating Water Sump internal inspections – all units;
- Oil Water Separator internal inspections;
- Underground Fire Piping – assessment;
- Marine Terminal assessments including fenders (with pin measurements) and pilings inspections;
- Fuel Oil Storage Tanks – external assessments of all tanks;

- Fuel Oil Storage Tank #3 - paint assessment and recommendations.

A plan for any further required capital investment will be developed from the results of this condition assessment and life extension study should pursuit of Phase Two be deemed appropriate.

Other items in addition to the condition assessment will be included in this study. As stated in the October 31 letter to the Board, the contractor will be responsible for studying other items and providing recommendations, as part of this assessment. Such items include:

- Identification of required operation and maintenance strategy for indefinite operation;
- Review of unit start-up times;
- Recommendations on minimum operating loads;
- Assessment of equipment lay-up requirements;
- Assessment of Unit 3 synchronous condenser conversion times;
- A review of standby operation targets in industry including recommendations;
- Recommendations on staffing level requirements;
- Recommendations with respect to environmental considerations including legislative requirements and requirements for the Certificate of Approval to Operate, which is issued by the Provincial Government;

Forced Outage Rate Methodology

November 15, 2019

A report to the Board of Commissioners of Public Utilities

newfoundland labrador hydro
a nalcor energy company

Executive Summary

The forced outage rate methodology applied to the Reliability and Resource Adequacy Study varied by asset class, ownership, and condition. Forced Outage Rates ("FOR") were determined based on historical data where available or the most recent industry average. The historical data is based on a weighted average of Derated Adjusted Forced Outage Rate ("DAFOR") for hydroelectric units and the thermal generating units at Holyrood Thermal Generating Station ("Holyrood TGS"); Derated Adjusted Utilization Forced Outage Probability ("DAUFOP") for gas turbine units; and Equivalent Forced Outage Rate Demand ("EFORd") for diesel units. For units not owned by Newfoundland and Labrador Hydro ("Hydro"), Canadian Electricity Association ("CEA") or North American Electric Reliability Corporation ("NERC") industry standards were used. FOR assumptions will be re-evaluated on an annual basis to incorporate the most recent data available. Table 1 provides a summary of values and measures used for existing generating assets. Table 2 provides a summary of values and measures used for expansion resource options.

Table 1: Forced Outage Rates for Existing Generating Assets

Unit Type	Measure	Near-Term Analysis Value (%)[1]	Resource Planning Analysis Value (%)[2]
Hydro-Owned			
Hydraulic[3]	DAFOR	2.8	2.1
Thermal	DAFOR	15 - 20	N/A
Gas Turbines			
Happy Valley	DAUFOP	9.8	9.7
Hardwoods and Stephenville	DAUFOP	30	N/A
Holyrood	DAUFOP	1.7	1.7
Diesel	EFORd	6.2	6.2
Power Purchases			
Corner Brook Pulp and Paper Co-Generation	DAFOR	15.8	N/A
Rattle Brook	DAFOR	5.7	5.7
Wind	N/A	N/A	N/A
Newfoundland Power Generation			
Hydraulic	DAFOR	5.7	5.7
Thermal	DAUFOP	13.6	13.6

[1] These values are used in Hydro's Near-term Reliability Assessments, which focus on system reliability in years 1 through 5.
[2] These values are used in Hydro's Near-term Reliability Assessments, which focus on system reliability in years beyond year 5.
[3] Includes units at Nalcor Energy Exploits Facilities.

Unit Type	Measure	Near-Term Analysis Value (%)[1]	Resource Planning Analysis Value (%)[2]
Deer Lake Power			
Capacity Assistance	N/A	N/A	N/A
Hydraulic	DAFOR	5.7	5.7

Table 2: Forced Outage Rates for Expansion Resource Options

Unit Type	Measure	Resource Planning Analysis Value (%)
Battery	FOR	0.5
Hydroelectric	DAFOR	2.1
Gas Turbines and Combined Cycle Combustion Turbines	DAUFOP	5.8
Wind	FOR	N/A
Solar	FOR	0.5

Contents

1.0 Hydroelectric Units

For Hydro-owned hydroelectric units (Bay d'Espoir Hydroelectric Generating Facility, Cat Arm Hydroelectric Generating Station, Hinds Lake Hydroelectric Generating Station, Granite Canal Hydroelectric Generating Station, Upper Salmon Hydroelectric Generating Station, and Paradise River Hydroelectric Generating Station) a 3-year capacity-weighted average DAFOR was applied to these units for the near-term analysis, while a 10-year capacity-weighted average DAFOR was applied for use in the resource planning model. The DAFOR value was based on historical data which is reflective of Hydro's maintenance program over the long term. The long-term DAFOR was also applied to the Muskrat Falls Hydroelectric Generating Station ("MFGS") and the Exploits Generation Hydroelectric Plant units as it is assumed they will be maintained to the same standards. Once historical operational data from MFGS is available, the DAFOR will be re-evaluated.

For hydroelectric units not owned by Hydro (Rattle Brook, Newfoundland Power Hydro, and Deer Lake) the CEA G-ERIS report, which collects outage statistics from utilities across Canada, was used to determine the DAFOR.[4] The DAFOR is based on a five-year average. It was applied across all units in both the near- and long-term modelling and analysis.

2.0 Holyrood Thermal Generating Station

DAFORs of 15%, 18%, and 20% were applied to the Holyrood TGS in order to determine the sensitivity of the system to Holyrood TGS availability in the near-term. This is consistent with Hydro's previous assessments of near-term reliability.

3.0 Gas Turbines

As the gas turbines in the existing fleet vary in age and condition, each was considered on an individual basis. For the Happy Valley Gas Turbine, a 3-year capacity-weighted average was applied to the unit for the near-term analysis, while a 10-year capacity-weighted average was applied for use in the resource planning model. The DAUFOP values were based on historical data founded upon the unit's past reliable performance. As the Holyrood Gas Turbine has only been in operation for the past four years, a 4-year average was used in both the near-term and resource planning analysis. For Hardwoods and

[4] "2018 Generation Equipment Status - Equipment Reliability Information System - Annual Report," Canadian Electricity Association, at p.29, table 6.1.2.

Stephenville Gas Turbines, a fixed DAUFOP consistent with values considered in Hydro's previous near-term reliability reports was used for the near-term analysis.[5]

4.0 Other

4.1 Corner Brook Pulp and Paper Co-Generation

A five-year average DAFOR is applied to both near- and long-term modelling and analysis. This value is based on the most recent CEA G-ERIS report for thermal-biomass units.[6]

4.2 St. Lawrence and Fermeuse Wind Farms

The forced outage rate is included in the probability distribution for both near- and long-term modelling and analysis.

4.3 Diesels

The EFORd from the most recent NERC Generating Availability Data System ("GADS") Report is applied to all diesel units for the near- and long-term modelling and analysis.[7,8] The EFORd is a measure used by NERC which is comparable to DAUFOP.[9]

4.4 Newfoundland Power Thermal

A 5-year average DAUFOP obtained from the most recent CEA G-ERIS report for combustion turbine units is applied for all gas turbine units in both near- and long-term modelling and analysis.[10]

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[5] "Near-Term Generation Adequacy Report," Newfoundland and Labrador Hydro, May 15, 2019.
[6] "2018 Generation Equipment Status - Equipment Reliability Information System - Annual Report," Canadian Electricity Association, at p. 90, table 6.2.18.
[7] "Generating Unit Statistical Brochure 4 (2014-2018) - All Units Reporting," North American Electric Reliability Corporation, July 30, 2019.< https://www.nerc.com/pa/RAPA/gads/Reports/Generating%20Unit%20Statistical%20Brochure%204%202014-2018%20-%20All%20Units%20Reporting.xlsx>
[8] As the Canadian Electricity Association does not track diesel forced outage rate, the NERC-GADS Report was used.
[9] IEEE Std 762-2006 "IEEE Standard Definitions for Use in Reporting Electric Generating Unit Reliability, Availability, and Productivity," IEEE Power Engineering Society, March 15, 2007.< https://www.nerc.com/docs/pc/gadstf/ieee762tf/762-2006.pdf>
[10] "2018 Generation Equipment Status - Equipment Reliability Information System - Annual Report," Canadian Electricity Association, at p. 103, table 6.3.2.

5.0 Long-Term Resource Planning Study: Expansion Resource Options

5.1 Batteries

A forced outage rate of 0.5% was used as per consultant recommendation.[11]

5.2 Gas Turbines and Combined Cycle Combustion Turbines

Both expansion options utilized a 5-year average DAUFOP based on the CEA G-ERIS report for combustion turbines that are between 0-10 years old.[12]

5.3 Hydroelectric Generation

Assumed DAFOR is consistent with Hydro-owned hydroelectric units used in the long term.

5.4 Solar Generation

A forced outage rate of 0.5% was used as per consultant recommendation.[13]

5.5 Wind Generation

The forced outage rate for the wind generation option was included in the probability distribution.

[11] Refer to "2018 Reliability and Resource Adequacy Study," Newfoundland and Labrador Hydro, September 6, 2019 (rev. 2), originally filed November 16, 2018), vol. III, att. 7.
[12] "2018 Generation Equipment Status - Equipment Reliability Information System - Annual Report," Canadian Electricity Association, at p. 103, table 6.3.2.
[13] Refer to "2018 Reliability and Resource Adequacy Study," Newfoundland and Labrador Hydro, September 6, 2019 (rev. 2), originally filed November 16, 2018), vol. III, att. 6.

Full Results of Resource Planning Cases

November 15, 2019

A report to the Board of Commissioners of Public Utilities

newfoundland labrador hydro
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Table 1: Case I – Island Interconnected System Mitigated Rate Case

	P50 Forecast		P90 Forecast	
Year	Labrador Expected	Labrador Industrial Growth	Labrador Expected	Labrador Industrial Growth
2020	-	-	-	-
2021	-	-	-	-
2022	-	-	-	-
2023	-	-	-	-
2024	-	-	-	-
2025	-	-	-	154 MW BDE 8
2026	-	-	154 MW BDE 8	-
2027	-	-	-	-
2028	-	-	-	-
2029	-	-	-	-

Table 2: Case II – Island Interconnected System Low Growth Case

	P50 Forecast		P90 Forecast	
Year	Labrador Expected	Labrador Industrial Growth	Labrador Expected	Labrador Industrial Growth
2020	-	-	-	-
2021	-	-	-	-
2022	-	-	-	-
2023	-	-	-	-
2024	-	-	-	-
2025	-	-	-	-
2026	-	-	-	-
2027	-	-	-	-
2028	-	-	-	-
2029	-	-	-	-

Table 3: Case III – Island Interconnected System High Growth Case

	P50 Forecast		P90 Forecast	
Year	Labrador Expected	Labrador Industrial Growth	Labrador Expected	Labrador Industrial Growth
2020	-	-	-	-
2021	-	-	-	-
2022	-	-	-	-
2023	-	-	-	-
2024	-	-	154 MW BDE 8	154 MW BDE 8
2025	-	-	-	-
2026	-	-	-	-
2027	-	-	-	-
2028	-	154 MW BDE 8	-	-
2029	154 MW BDE 8	-	-	-

Abbreviations

Abbreviations

Term	Definition
2018 Filing	Reliability and Resource Adequacy Study filed November 16, 2018
2019 Update	Reliability and Resource Adequacy Study filed November 15, 2019
AESO	Alberta Electric System Operator
Board	Board of Commissioners of Public Utilities
CAISO	California Independent System Operator
CBPP	Corner Brook Pulp and Paper Limited
CDM	Conservation and Demand Management
CEA	Canadian Electricity Association
CF(L)Co	Churchill Falls (Labrador) Corporation
CFA	Cumulative Frequency Analysis
CPP	Critical Peak Pricing
DAFOR	Derated Adjusted Forced Outage Rates
DAUFOP	Derated Adjusted Utilization Forced Outage Probabilities
DND	Department of National Defence
DOMAE	Department of Municipal Affairs and Environment
Dunsky	Dunsky Energy Consulting
EFLA	EFLA Consulting Engineers
ELCC	Effective Load Carrying Capability
EUE	Expected Unserved Energy

Term	Definition
EV	Electric Vehicle
FOR	Forced Outage Rate
GDP	Gross Domestic Project
GT	Gas Turbine
Hardwoods GT	Hardwoods Gas Turbine
Holyrood TGS	Holyrood Thermal Generating Station
HVdc	High Voltage Direct Current
Hydro	Newfoundland and Labrador Hydro
IESO	Independent Electrical System Operator
IOC	Iron Ore Company of Canada
ISO-NE	ISO New England
Liberty	The Liberty Consulting Group
Liberty's Review	"Review of Newfoundland and Labrador Hydro's Reliability and Resource Adequacy Study," filed with the Board August 19, 2019
LIL	Labrador-Island Link
LOLE	Loss of Load Expectation
LOLH	Loss of Load Hours
LOLP	Loss of Load Probability
LTA	Labrador Transmission Assets
MFGS	Muskrat Falls Generating Station
MISO	Mid-Continent Independent System Operator
MgO	Magnesium Oxide

Term	Definition
NEM	Nalcor Energy Marketing
NERC	North American Electricity Reliability Corporation
NLSO	Newfoundland and Labrador System Operator
Nova Scotia Block	The Nova Scotia Block is a firm annual commitment of 980 GWh, to be supplied from the MFGS on peak.
NPCC	Northeast Power Coordinating Council
NYISO	New York Independent System Operators
O&M	Operation and Maintenance
OASIS	Open Access Same-Time Information System
OEM	Original Equipment Manufacturer
PM	Preventative Maintenance
Reference Question	Reference on Rate Mitigation Options and Impacts Relating to the Muskrat Falls Project Costs
Reliability Model	Detailed Hourly System Model
Resource Planning Model	Long-Term Resource Planning Model
RFP	Request for Proposal
SEM	System Equipment and Maintenance
Stephenville GT	Stephenville Gas Turbine
Supplemental Energy	Commitment to Firm Energy
Synapse	Synapse Energy Economic
TOU	Time of Use
TwinCo	Twin Falls Power Corporation
UPS	Uninterruptible Power Supply

Term	Definition
Vale	Vale Newfoundland and Labrador Limited
VFD	Variable Frequency Drives
VOLL	Value of Loss Load

Definitions

Adequacy: The ability of the electric system to supply the aggregate electrical demand and energy requirements of the end-use customers within the system criteria, taking into account scheduled and unscheduled outages of system elements.[1]

Adjusted Gross Domestic Product: Excludes income that will be earned by the non-resident owners of provincial resource developments to better reflect growth in economic activity that generates income for local residents.

Base Case: The base case is the expected case, determined by using the assumptions considered most likely to occur.

Capacity Assistance: Contracted curtailable loads and customer generation that can be called on for system support. Capacity assistance agreements are generally restricted in terms of frequency, duration and annual usage.

Coincidence Factor: The coincidence factor is a measure of the likelihood of the independent systems peaking at the same time. For the Newfoundland and Labrador Interconnected System, it provides a measure of the relative contribution of the Island Interconnected System and the Labrador Interconnected System peaks to the combined Newfoundland and Labrador Interconnected System Peak.

Consumer Price Index: The consumer price index is an indicator of the change in consumer prices. It measures price change by comparing through time the cost of a fixed-basket of consumer goods and services.[2]

Critical Peak Pricing: Critical peak pricing offers customers time-varying rates that reflect the cost of capacity during critical peak times. By significantly increasing the rate during that time, customers are incented to significantly shift or reduce demand during the critical peak period.

Curtailable Load: A load, typically commercial or industrial that can be interrupted at the request of the system operator.

Demand: (1) The rate at which electric energy is delivered to or by a system or part of a system, generally expressed in kilowatts (kW) or megawatts (MW), at a given instant or averaged over any designated interval of time. (2) The rate at which energy is being used by the customer.[3]

[1] "Reliability Assessment Guidebook," NERC, March 2008, Version 1.2 <https://www.nerc.com/comm/PC/Reliability%20Assessment%20Subcommittee%20RAS%20DL/Reliability%20Assessment%20Guidebook/Reliability_Assessment_%20Guidebook%20v1.2%20031909.pdf>
[2] Statistics Canada, "Chapter 1 – Introduction to the Canadian Consumer Price Index," November 30, 2015. <https://www150.statcan.gc.ca/n1/pub/62-553-x/2014001/chap/chap-1-eng.htm>
[3] "Reliability Assessment Guidebook," NERC, March 2008, Version 1.2 <https://www.nerc.com/comm/PC/Reliability%20Assessment%20Subcommittee%20RAS%20DL/Reliability%20Assessment%20Guidebook/Reliability_Assessment_%20Guidebook%20v1.2%20031909.pdf>

Demand-Side Management (also known as Customer Demand Management): The term for all activities or programs undertaken by the utility and/or its customers to influence the amount or timing of electricity they use.[4]

Derated Adjusted Forced Outage Rate ("DAFOR"): Measures the percentage of time that a unit or group of units is unable to generate at its Maximum Continuous Rating ("MCR") due to forced outages.

Derated Adjusted Utilization Forced Outage Probability ("DAUFOP"): The probability that a generating unit will not be available due to forced outages or forced deratings when there is demand on the unit to generate.

Deterministic Analysis: Uses a set of known and fixed system conditions and probabilities (load, forced outage rates, transmission flows, and intermittent generation) to determine system reliability. Deterministic analysis is computationally efficient but does not consider many of the uncertainties present in real-world systems.

Dispatchable Resource: A dispatchable resource is a generation resource that can be used on demand and increased or decreased at the request of operators, according to system needs.

Effective Load Carrying Capability ("ELCC"): A metric used to assess firm capacity credit for intermittent generation resources. It is a measure of the additional load that the system can supply with the addition of a generator with no net change in reliability.

Electrical Power Control Act, 1994 ("EPCA"): The Act which regulates the electrical power resources of Newfoundland and Labrador.[5]

Emergency Operating Procedure ("EOP"): A procedure that includes a number of possible mitigating actions that can be enacted by the system operator, as required, to provide system relief.

Expected Unserved Energy ("EUE"): A measure of the amount of customer demand not served due to generation shortfalls.

Firm Capacity: the amount of generation capacity available for production or transmission guaranteed to be available when the unit is operational.

Firm Demand: That portion of the demand that a power supplier is obligated to provide, except when system reliability is threatened or during emergency conditions.[6]

Firm Energy: Firm energy refers to the actual energy guaranteed to be available to meet customer requirements.

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[4] Ibid.
[5] *Electrical Power Control Act, 1994* Chapter E-5.1. <https://www.assembly.nl.ca/legislation/sr/statutes/e05-1.htm>
[6] "Reliability Assessment Guidebook," North American Electric Reliability Corporation, March 2008, Version 1.2 <https://www.nerc.com/comm/PC/Reliability%20Assessment%20Subcommittee%20RAS%20DL/Reliability%20Assessment%20Guidebook/Reliability_Assessment_%20Guidebook%20v1.2%20031909.pdf>

Firm Imports and Exports: A contract for the import or export of capacity or energy guaranteed to be available at a given time.

Forced Outage: (1) The removal from service availability of a generating unit, transmission line, or other facility for emergency reasons. (2) The condition in which the equipment is unavailable due to unanticipated failure.[7]

Forced Outage Rate ("FOR"): The expected level of unavailability of a unit due to unforeseen circumstances.

Gross Domestic Product ("GDP"): GDP is the total unduplicated value of the goods and services produced in the economic territory of a country or region during a given period.[8]

Island Interconnected System: The interconnected portion of the island's electrical system. It is characterized by large hydroelectric generation capability located off the Avalon Peninsula, the Holyrood Thermal Generating Station on the Avalon Peninsula, and the bulk 230 kV transmission system extending from Stephenville in the west to St. John's in the east. The Island Interconnected System is interconnected to the Labrador Interconnected System via the Labrador-island Link ("LIL"). The Island Interconnected System is also connected to the North American grid via the Maritime Link.

Labrador Interconnected System: The interconnected portions of Labrador's electrical system form the Labrador Interconnected System. It is characterized by supply at Churchill Falls (provided by TwinCo Block and Recapture Energy), radial transmission to the two major load centres in Labrador East and Labrador West, and the Labrador Transmission Assets ("LTA") connecting Churchill Falls to Muskrat Falls. The Labrador Interconnected System is connected to the Island Interconnected System via the LIL. The Labrador Interconnected System is also connected to the North American grid via the 735 kV ac transmission lines from Churchill Falls to Quebec.

Labrador-Island Link ("LIL"): A 900 MW high voltage dc transmission line designed to deliver power from the Muskrat Falls Generating Station to Soldiers Pond Terminal Station on the Avalon Peninsula.

Load Forecast: The projected energy and demand requirements for the electrical system. The load forecast process entails translating a long-term economic and energy price forecast for the Province into corresponding electric demand and energy requirements for the electric power systems. Hydro predicts future load requirements for the Island Interconnected System primarily through econometric modelling techniques and large industrial customer input. Future load requirements for the Labrador Interconnected system are primarily through historical trend analysis and large industrial customer input.

Load Forecast Uncertainty: A multiplier representing the potential variance in annual peak demands. Its development is based on a distribution of expected values of load based upon an analysis of the weather sensitivity of peak loads.

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[7] Ibid.
[8] Statistics Canada, "Gross Domestic Product (GDP).", September 20, 2017 <https://www.statcan.gc.ca/eng/nea/list/gdp>

Loss of Load Expectation ("LOLE"): The expected number of days each year where available generation capacity is insufficient to serve the daily peak demand.

Loss of Load Hours ("LOLH"): Loss of Load Hours is the expected number of hours per year when a system's hourly demand is projected to exceed the generating capacity. This metric is calculated using each hourly load in the given period instead of using only the daily peak in the LOLE calculation.

Loss of Load Probability ("LOLP"): The probability of system daily peak or hourly demand exceeding available generating capability in a given study period.

Maritime Link: A high voltage dc transmission line connecting Newfoundland and Nova Scotia.

Maximum Continuous Rating ("MCR"): The maximum continuous rating is defined as the maximum output in MW that a generating station is capable of producing continuously under normal operating conditions over a year.

Monte Carlo Simulation: A mathematical technique that generates random variables for modelling risk or uncertainty of a certain system.

Newfoundland and Labrador Interconnected System: The Island Interconnected System and the Labrador Interconnected System combine to form the Newfoundland and Labrador Interconnected System.

North American Electric Reliability Corporation ("NERC"): A non-profit, self-regulating organization whose objective is to ensure adequate reliability of the bulk power system in North America.

Northeast Power Coordinating Council, Inc. ("NPCC"): NPCC is a regional entity division which operates under a delegation agreement with the North American Electric Reliability Corporation (NERC). Members include the State of New York and the six New England states as well as the Canadian provinces of Ontario, Québec, and the Maritime provinces of New Brunswick and Nova Scotia.

Nova Scotia Block: A firm commitment of 980 GWh, to be supplied annually from the Muskrat Falls Generating Station on peak.

Non-Dispatchable Resource: A non-dispatchable resource is an energy resource, such as wind power, that can not be used on demand and dispatched as per system needs.

Non-Firm Imports and Exports: A contract for the import or export of capacity or energy which is not guaranteed to be available at a given time.

Non-Spinning Reserve: (1) That generating reserve not connected to the system but capable of serving demand within a specified time. (2) Interruptible load that can be removed from the system in a specified time.[9]

[9] "Reliability Assessment Guidebook," North American Electric Reliability Corporation, March 2008, Version 1.2 <https://www.nerc.com/comm/PC/Reliability%20Assessment%20Subcommittee%20RAS%20DL/Reliability%20Assessment%20Guidebook/Reliability_Assessment_%20Guidebook%20v1.2%20031909.pdf>

Normalized Expected Unserved Energy: A measure of the amount of customer demand not served due to generation shortfalls divided by the total system energy.

Operational Reserve: A system requirement where the system requires the ability to withstand the loss of the single largest resource while maintaining an additional reserve.

Peak Demand: The highest hourly demand on a system occurring within a year.[10]

Planning Reserve Margin: The reserve margin at which the system reliability is at criteria. It is used as a reliability metric to evaluate the system's resource adequacy for expansion planning.

Probabilistic Analysis: Probabilistic analysis simulation requires completion of several simulations using randomly sampled variables like outage profiles, wind generation and weather related load uncertainty to determine system reliability. When compared to deterministic analysis, probabilistic analysis better incorporates the random behavior of system states as well as the operational restrictions of the system. See Monte Carlo Analysis.

Power Purchase Agreement ("PPA"): A contract for the purchase of capacity and/or energy from a third party.

P50 Forecast: A P50 forecast is one in which the actual peak demand is expected to be below the forecast number 50 percent of the time and above 50 percent of the time (i.e.. the average forecast.)

P90 Forecast: A P90 forecast is one in which the actual peak demand is expected to be below the forecast number 90 percent of the time and above 10 percent of the time (i.e., there is a 10 percent chance of the actual peak demand exceeding the forecast peak demand.)

Reserve Margin: The amount by which available firm capacity exceeds capacity required to meet peak demand.

Run-of-River: Hydroelectric generating facilities with limited storage capability, where production is dictated by the water available in the river at the time of generation.

Sensitivities: Cases developed to study the impact of change in variables on resource planning analysis. These sensitivities include addition of large loads in Labrador, and the uncertainty in load projections associated with future customer rates.

Spinning Reserve: Unloaded generation that is synchronized and ready to serve additional demand.[11] Also referred to as synchronized reserve.

[10] Ibid.
[11] Ibid.

Supplemental Energy: A firm energy commitment to supply energy to Nova Scotia during the first five years of production at the Muskrat Falls Generating Station as part of the Amended and Restated Energy and Capacity Agreement.

Synchronized Reserve: Refer to Spinning Reserve.

System Operator: Entity entrusted with the operation of the control center and the responsibility to monitor and control the electric system in real time.[12]

Time-of-use-Rates: An option for customers that offers electricity rates that vary throughout the day based on load patterns; with the highest rates during peak hours and lowest rates during off-peak hours.

Transmission Constraint: A limitation on one or more transmission elements that may be reached during normal or contingency system operations.[13]

Underfrequency Load Shedding ("UFLS"): the automatic or manual actions required to shed system load when the system frequency falls below defined acceptable parameters.

Utilization Forced Outage Probability ("UFOP"): is the probability that a generating unit will not be available due to forced outages when there is demand on the unit to generate.

[12] Ibid.
[13] Ibid.