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May 16, 2022

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 Review* – Near-Term Reliability Report

Further to the Board of Commissioners of Public Utilities' correspondence of October 13, 2016, requesting semi-annual reports on May 15 and November 15 each year on generation adequacy for the Island Interconnected System, enclosed please find Newfoundland and Labrador Hydro's Near-Term Reliability Report.

Should you have any questions, please contact the undersigned.

Yours truly,

NEWFOUNDLAND AND LABRADOR HYDRO

SWalsh

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Reliability and Resource Adequacy Study
2022 Update

Volume II: Near-Term Reliability Report – May Report

May 16, 2022

A report to the Board of Commissioners of Public Utilities

Contents

1.0 Introduction

Supply adequacy in advance of the availability of full production from the Muskrat Falls Project assets remains a critical consideration for Newfoundland and Labrador Hydro ("Hydro") and its stakeholders. The enclosed assessment of near-term resource adequacy provides an in-depth view of system risks and mitigating measures to ensure customer requirements are met through the full system transition.

This report discusses the near-term resource adequacy and reliability and provides the results of the probabilistic resource adequacy assessment of the Newfoundland and Labrador Interconnected System for the 2022–2025 study period. The analysis was conducted consistent with the methodology 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."[1]

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 ("NEUE").[2] 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 "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 are more easily observed than by using an annual analysis only. As LOLH and EUE do not currently have generally acceptable criteria, unlike the generally accepted Loss of Load Expectation ("LOLE") criterion of 0.1, the quantified results show how loss of load changes based on system conditions rather than for comparison against a threshold.

[1] "Probabilistic Assessment Technical Guideline Document," North American Electric Reliability Corporation, August 2016.
[2] NEUE provides a measure relative to the size of the assessment area. It is defined as: [(Expected Unserved Energy)/(Net Energy for Load)] × 1,000,000 with the measure of per unit parts per million ("ppm").

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.

Given the current evolving nature of the Newfoundland and Labrador Interconnected System, an analysis was conducted for the period from 2022–2025 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. With respect to the Muskrat Falls Project, since Hydro's November 2021 Near-Term Reliability Report ("November Report"),[3] the Muskrat Falls Generation Station has been fully commissioned. Additionally, since filing the November Report, the asset owners have approved the Labrador-Island Link ("LIL") for operation up to 450 MW. To date, the LIL has been successfully tested and operated at 435 MW, an increase from the prior established operational limit of 312 MW.

As has been observed in prior near-term reliability reports, results of Hydro's analysis indicate that reliable operation of the LIL is shown to provide significant system reliability benefits even at low power transfer levels. While power transfer over the LIL is expected throughout the 2022–2023 winter operating season, Hydro has prepared this analysis in a manner consistent with prior analysis by considering and analyzing system reliability through the entire reporting period with an assumption that the LIL will not be available for the reporting period to provide a fulsome view of potential system reliability.

Finally, Hydro has also included assessments of the increased level of reliability resulting from supplementing Island supply with imports over the Maritime Link.

[3] "Reliability and Resource Adequacy 2021 Update – Volume II: Near-Term Reliability Report – May Report," Newfoundland and Labrador Hydro, May 17, 2021.

2.0 Modelling Approach

The analysis in this report has been completed using Hydro's reliability model. This model has been used to assess system reliability since the "Reliability and Resource Adequacy Study," filed in November 2018 ("2018 Filing"),[4] with updates to reflect current system assumptions.[5]

Transmission system adequacy is assessed separately in accordance with Transmission Planning Criteria; these assessments are posted publically on the Newfoundland and Labrador System Operator ("NLSO") Open Access Same-Time Information System ("OASIS") website.

3.0 Asset Reliability

On a quarterly basis, reports are filed with the Board which include actual forced outage rates ("FOR") 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 April 29, 2022, for the quarter ended March 31, 2022.[7] 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 that frequently involve external experts, addressing issues with urgency, and placing an increased focus on asset reliability.

[4] "Reliability and Resource Adequacy Study," Newfoundland and Labrador Hydro, rev. September 6, 2019 (originally filed November 16, 2018).
[5] Volumes I and II of the 2018 Filing provide a detailed discussion of the initial modelling approach used. A discussion of changes to the model from the 2018 Filing can be found in Volume I of the "Reliability and Resource Adequacy Study – 2019 Update," Newfoundland and Labrador Hydro, November 15, 2019 ("2019 Update").
[6] Quarterly Report on Performance of Generating Units.
[7] "Quarterly Report on Performance of Generating Units for the Twelve Months Ended March 31, 2022," Newfoundland and Labrador Hydro, April 29, 2022.

3.1 Factors Affecting Recent Historical Generating Asset Reliability

Hydro has reviewed the factors affecting generating unit reliability since filing its November Report. Updates on these items, as well as any additional items which may impact asset performance in the near term, are provided in this report. 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 3.1.1 through 3.1.3 of this report provides 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 Rate ("DAFOR") and Derated Adjusted Utilization Forced Outage Probabilities ("DAUFOP").

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 generating assets (e.g., penstock, boiler tubes), but also considers environmental challenges impacting operations (e.g., frazil ice conditions). As part of this exercise the following items have been identified, grouped by facility type:

- Hydraulic Facilities: Continued monitoring (Bay d'Espoir penstocks, and Upper Salmon rotor rim key cracking and rotor rim guidance block defects), ongoing (Granite Canal control system);
- Thermal Facilities: Continued monitoring (Power Centre C failure, boiler feed pump motor issues, variable frequency drives, T2 power transformer failure), ongoing (unit boiler tubes), and resolved (cold reheat pipe water hammer event,); and
- Gas Turbines: New and Resolved (Hardwoods end B intermittent starting issues).

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.

3.1.1 Hydraulic

Bay d'Espoir Penstocks

Condition assessments of Bay d'Espoir Penstocks 1, 2, and 3 were conducted in 2018, which included the completion of three reports prepared by a third-party consultant. These reports have been filed with the Board.[8] In response to the most recent September 2019 failure of Penstock 1, SNC-Lavalin Group Inc. was engaged to complete an independent, detailed failure analysis of the most recent rupture, as well as an engineering review of the work previously completed by Hatch Ltd. The results of this failure analysis and engineering review were filed with the Board on June 3, 2020.[9] As outlined in that correspondence, Hydro is currently pursuing Stage 2, front-end engineering design ("FEED"). Kleinschmidt are engaged to perform all functions of the FEED, which is anticipated to be completed by the end of the third quarter of 2022. The results of the FEED will detail an investment strategy plan for life extension activities related to all three Bay d'Espoir penstocks.

Hydro has continued to take proactive measures to reduce downtime should another penstock leak occur, including maintaining an inventory of pre-rolled steel plate, and confirmed availability of local welding resources. Modifications to the Automatic Generator Control application in Hydro's Energy Management System, designed to limit the amount of rough zone operation, have remained in place for Units 1 to 6 at Bay d'Espoir. A more prescriptive operating regime has also remained in place for Units 1 and 2 given the history of 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.

The 2022 inspection for Penstock 1 was completed on April 28, 2022. During the inspection, two weld indications were discovered in previously repaired areas of the penstock. These indications were assessed and it was deemed necessary to complete repairs to ensure continued reliable operation. Repairs were completed and the penstock was returned to service on May 2, 2022. The remaining 2022 inspections have been scheduled and Hydro will provide an update of the outcomes in its November 2022 update of this report, or as required should deficiencies be identified. Hydro will use the

[8] "Bay d'Espoir Level II Condition Assessment of Penstock No. 1, 2, and 3," Hatch Ltd., rev. 0, December 13, 2018, filed with the Board on December 17, 2018; "Final Report for Condition Assessment and Refurbishment Options for Penstocks 1, 2 and 3," Hatch Ltd., rev. 0, March 28, 2019, filed with the Board on March 29, 2019; and "Final Report for Penstock No.'s 1, 2 and 3 Life Extension Options," Hatch Ltd. rev. 0, July 26, 2019 filed with the Board on July 30, 2019.
[9] "2019 Failure of Bay d'Espoir Penstock 1 and Plan Regarding Penstock Life Extension," Newfoundland and Labrador Hydro, June 3, 2020.

information obtained through the inspection and refurbishment process to inform its long-term plan for the penstocks; the details of Hydro's long-term plan are expected to be filed with the Board in 2022.

Although Hydro has mitigated risk of failure to the extent possible, there is residual risk that a failure could occur before further life extension work is executed. Hydro has estimated a 13- to 23-day repair timeline, depending on circumstances, should a new failure occur.

Upper Salmon Rotor Key Cracking and Rotor Rim Guidance Block Defects

As previously reported, in 2018, the rotor rim keys on the Upper Salmon generating unit were replaced during the unit annual maintenance outage. As per consultation with the original equipment manufacturer ("OEM"), Hydro has continued to schedule and conduct regular inspections of the new rotor rim keys at Upper Salmon throughout the anticipated wear-in period to assess the effectiveness of the replacement keys. After a 2019 reseating of the keys, inspections were scheduled every four weeks; this was extended to six weeks in 2020 after successive inspections found no signs of cracking. Superficial cracks were identified and resolved during the August 2020 inspection; however, inspections completed between August 2020 and the annual maintenance outage in August 2021 revealed no new cracking.

During the 2021 planned annual preventative maintenance checks in August 2021, a significant crack on one of 16 rotor rim guidance blocks was discovered. The discovery of this crack prompted Hydro to expand its inspection scope to include the use of non-destructive testing ("NDT") methods to assess the remaining rim guidance blocks. The results from this expanded inspection revealed that over 35% (6 of 16) of the rim guidance blocks exhibited cracking.

In consultation with the OEM for the equipment, it was determined that the cracking was beyond repair and block replacement was immediately required before the unit could be placed back into reliable service. As recommended by the OEM, all 16 blocks were replaced during a forced extension to the planned outage. The Upper Salmon unit was returned to service on October 22, 2021.

The OEM considers contributing factors to this issue to be a combination of an out-of-round stator and a loose rotor rim. While addressing this life extension work was not possible prior to the 2021–2022 winter season, replacement of the blocks was considered a suitable approach by the OEM to reduce the residual risk to an acceptable level for operation in the coming winter operating season. In addition to the block replacement, the OEM has recommended implementing a NDT inspection program of the blocks at 12-week intervals until the life extension work scope is completed. Hydro now includes this inspection program in its maintenance activities.

Through subsequent NDT inspections completed in November 2021, February 2022, and May 2022, which revealed no material concerns with newly installed blocks; however, cracks were found on rim keys as have been previously seen. Following further consultation with the OEM, it was advised to increase the frequency of scheduled inspections from every 2,000 hours to every 1,000 hours for the next two inspections. If results of those two inspections are favourable, the OEM has advised that inspections can continue at the prior frequency of every 2,000 hours. Hydro submitted a supplemental capital budget application on April 26, 2022 to undertake additional work to address the required life extension activities.[10]

Although Hydro has mitigated risk of failure to the extent possible in the near term, there is residual risk that a failure could occur before execution of the required life extension work scope. To offset the impact of an unplanned outage, Hydro is advancing procurement of long lead materials that would address the underlying contributing factors, details of which are outlined in the supplemental capital budget application.

Granite Canal Control System

A thorough engineering assessment of the Granite Canal control system has been completed in response to control system malfunctions experienced when remotely starting and/or stopping the Granite Canal unit. Modifications to equipment, as well as minor logic changes, were implemented in 2019. Additional hardware and instrumentation modifications were implemented during the maintenance outage in June 2020 to address findings of the 2019 assessment. While there have not been any starting issues recently, there have been an increased number of outages due to component failures. A further investigation regarding the remaining useful life of the control system has been completed. It has been determined that control system hardware, which was originally installed in 2003 at the time of the units commissioning, is either presently or soon to be obsolete and will require replacement. This replacement is now reflected in the long-term plan and required capital work will be proposed as part of the capital budget process in an appropriate future year. To ensure continued

[10] "Application for Approval for Rotor Rim Shrinking and Stator Recentering at the Upper Salmon Hydroelectric Generating Station," Newfoundland and Labrador Hydro, April 26, 2022.

reliability of this system until such a time as the replacement is complete, a thorough review of necessary spare components was completed and all identified items are available or in the process of being procured.

3.1.2 Thermal

Power Centre C Failure

Following a unit trip caused by Power Centre C, a 600 V load centre going offline, a TapRooT investigation determined the root cause leading to the Unit 1 trip and load limitation on Unit 2 was determined to be that the breaker which protects compressor #1 had its instantaneous element (50G) disabled. This caused a chain of events that resulted in the trip of Power Centre C, the trip of Unit 1, and the temporary inability to increase load on Unit 2.[11] The corrective action to enable the 50G element in the compressors' breakers was completed as part of the annual maintenance program in 2021. This will prevent recurrence of this failure.

Other follow up actions were identified in the investigation. A review of the loads connected to each power centre was completed in 2021 for all power centres to determine if power centre unavailability would cause a trip or derate of operating units. The review found no concerns other than the two air compressors being fed from Power Centre C. In addition, a fusing review will be conducted in 2022, with work planned to be completed during the planned annual outages.

Hydro will provide more information on the results of the follow-up actions in the November 2022 update of this report.

Boiler Feed Pump Motors

Following a failure of the Unit 1 boiler feed pump west which forced Unit 1 offline and to remain derated for a period of time once returned to service, a TapRooT investigation determined the root cause of the pump failure was a miscommunication which led to the suction valve being closed on the operating pump in error. The investigation also identified some safe guards that were not in place that could have mitigated the failure including modifications to the control logic, which was not set up to trip the feed pump when the suction valve was moved from the open position, as well as motor protection settings, and preventive maintenance practices.

[11] For additional detail on the outage itself and the outcomes of Hydro's TapRooT investigation, please refer to Hydro's November Report.

Control logic modifications to trip a boiler feed pump if the suction valve moves off the open position has been implemented. This will prevent recurrence of this issue. The other recommended corrective actions from the investigation are complete or planned to be completed in 2022. Preventive maintenance strategies have been modified to include mechanical assessment of critical components of 4,160 V motors. Interlocking logic is being reviewed for all 4,160 V motors in the plant. Some settings have been updated and the remainder will be completed during the 2022 outages.

Hydro will provide the updated status of these actions in the November 2022 update of this report.

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. Boiler tubes are inspected on an annual basis to verify their condition and to identify trends.

To mitigate the possibility of tube failures, Hydro conducts a thorough annual tube inspection and test program, which will be executed during the 2022 annual outage season. Hydro has determined that boiler tube sections, as a whole, are in good condition. Tube failures continue to pose a risk, particularly given the age of the Holyrood TGS boilers. Hydro maintains a thorough selection of spare tube material and a contract with an experienced boiler contractor for the provision of emergency repairs in the event of tube failures.

As discussed in the November Report, Holyrood TGS experienced a tube leak on the Unit 3 boiler on September 11, 2021 during start-up. This failure occurred in a known trouble spot on this unit, which is caused by stresses induced where the windbox attaches to the tubes.

Hydro engaged industry expertise including the boiler service provider (General Electric), the Boiler OEM (Babcock and Wilcox), a metallurgical laboratory (Wayland Engineering), and an expert boiler tube inspection company (TesTex) to assist in the process of investigating and mitigating this failure.

After completion of a full investigation, condition assessment of tubes, and removal of tube defects, Hydro considered the specific issue on Unit 3 to be resolved. The unit was returned to service on November 19, 2021 and operated reliably throughout the 2021–2022 winter season. It should be noted that the other two boilers at Holyrood TGS do not have large structural attachments to the cold side of the tubes and consequently are not susceptible to this failure mechanism.

Variable Frequency Drives

Forced draft fans provide combustion air required for boiler operation at the Holyrood TGS. The Variable Frequency Drives ("VFDs") 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.

Since installation, Hydro has dealt with significant reliability issues related to this equipment, despite engaging the OEM for annual preventive maintenance work, and also following OEM recommendations to take significant mitigating measures to keep the drives clean and dry during outage periods, and also to pre-energize the VFDs prior to start-up.

In September of 2021, Siemens advised that global shortages of microchips and other electronic components would extend turnaround time for failed power cells to between 48 and 52 weeks. As a result of this, and nine recent failures of power cells, Hydro had concern regarding the availability of spare cells to support operation and made a decision to bypass the VFDs on Unit 3 prior to the 2021–2022 winter operating season. This work was successful and Unit 3 performed reliably throughout the season.

Hydro has made plans to bypass the VFDs on the remaining two units during the 2022 maintenance outage season. This longstanding reliability issue will then be resolved. Hydro will provide the status of this work in the November 2022 update of this report.

Cold Reheat Pipe Water Hammer Event – Unit 1

On October 25, 2021, when starting up Unit 1 after completion of the annual maintenance outage, which included a major turbine overhaul, there was a sudden and significant movement of the cold reheat pipe that supplies steam from the turbine to the boiler reheater. Damage to the supports and insulation on this line was evident and start-up was abandoned to allow an investigation of the cause of the event and assessment of the associated damage.

The investigating team determined that water had been leaking into the cold reheat pipe through a spray station that is designed to control reheat steam temperature when online. The presence of this water during start-up led to a water hammer event, which caused the observed damage.

Expert consultation was provided by GE, the boiler and turbine OEM and service provider for the plant, and third-party experts from Hatch. The extent of damage was determined through inspection as recommended by the experts. Scaffolding was erected and insulation removed from areas of concern to allow non-destructive evaluation and visual inspection. The boiler reheater section was also inspected and leak checks performed.

After completion of all remedial work including replacement of damaged pipe hangers and re-welding of failures at the reheat header to tube welds and at the condensate drain, the unit was returned to service on December 1, 2021. The unit operated reliably for the 2021–2022 winter operating season. Hydro considers this issue to be resolved.

T2 Power Transformer Failure – Unit 2

Power transformer T2 failed on November 12, 2021. The failed transformer was replaced with the on-site spare. The unit was returned to service for commissioning of the spare transformer on January 12, 2022 and was released for service by the NLSO on January 13, 2022. The installed spare transformer operated reliably for the 2021–2022 winter operating season. Due to the specifications on the spare transformer that was installed, the full load capability of Unit 2 with the replaced power transformer is 150 MW. Investigation into the cause of the failure remains ongoing. Hydro has engaged outside technical support through both Hitachi Energy (ABB) and Doble Engineering to assist with this investigation. Hydro will continue to monitor the health of T2 and will also provide the status of the investigation in the November 2022 update of this report.

3.1.3 Gas Turbines

Hardwoods Gas Turbine – End B Starting Issues

From December 16, 2021 to December 21, 2021 the Hardwoods Gas Turbine was derated to 25 MW due to an intermittent starting issue on End B. Investigation into the issue identified low air system pressure due to a slow acting starting motor and a failed pressure control valve resulting in slow acceleration of the engine during start-up. Low fuel pressure was also identified and was determined to be the result of the output settings of the on-engine fuel pump and main fuel control valve. These issues compounded during times of cold ambient temperatures preventing the unit from successfully starting on a consistent basis. Corrective maintenance was completed on the engine's air system (installation of spare components) and fuel system (fuel pump and valve adjustments) to ensure the air and fuel pressures were within specification. Since this action has been taken the engine has consistently started as expected. Hydro considers this issue resolved.

3.2 Selection of Appropriate Performance Ratings

3.2.1 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 FORs provide a measure of the expected level of availability due to unforeseen circumstances.[12] Assumptions on FORs of generating units are updated annually in accordance with Hydro's FOR methodology.[13]

The FORs used in Hydro's reliability analysis vary by asset class, ownership, and condition. Appropriate FORs are determined using historical data, where available, industry data, and scenario-based approaches. 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. Industry information made available through the Canadian Electricity Association ("CEA") and NERC is used to determine FORs for units not owned by Hydro.

FOR assumptions are developed annually to incorporate the most recent data available. Table 1 summarizes the projected availability of Hydro's generating assets considered in the assessment of near-term supply adequacy. These projections of asset reliability include appropriate consideration of asset availability and deration.

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[12] FOR refers to an input to the reliability model, which represents the percentage of hours in a year when a unit is unavailable.
[13] In this report, Hydro deviated from the FOR methodology as outlined in the 2019 Update when selecting FORs for its hydroelectric units and for the Holyrood Gas Turbine ("Holyrood GT"). In both cases, Hydro believed the result of the prescribed methodology did not accurately represent the risk of unit outage. For the hydroelectric units, Hydro maintained the capacity-weight average DAFOR from the November Report, which is higher than the 5-year DAFOR, increasing the FOR to more appropriately represent the risk of failure in the near term. For the Holyrood GT, Hydro used a scenario-based approach to estimate the FOR.

Table 1: Forced Outage Rates for Hydro-Owned Assets

Asset	Reliability Metric
Hydraulic Units	DAFOR = 2.6%
Holyrood Thermal Units – Base Assumption	DAFOR = 15%
Holyrood Thermal Units – Sensitivity Assumptions	DAFOR = 20%, 34%
Holyrood GT	DAUFOP = 4.9%
Happy-Valley GT[14]	DAUFOP = 12%
Stephenville GT[15]	DAUFOP = 30%
Hardwoods GT[16]	DAUFOP = 30%
Diesels	DAUFOP = 6.3%

With respect to the LIL, once modelled as in service, its availability is modelled with a declining FOR (i.e., improving performance) in order to capture any testing activities and potential operational unknowns during the first years of operation.[17] Given the continued delays experienced in commissioning to date and the complexity of the commissioning process, Hydro's methodology remains consistent with prior Near-Term Reliability Reports, and assumes a FOR of 10% in 2022, declining to 5% in 2023, 2.5% in 2024 and 1.0% in 2025. This ensures a prudent approach with respect to asset availability during the early years of in-service.

For the purpose of this analysis, the LIL is assumed to be available at a reduced capacity of 450 MW until January 2023, and at full capacity thereafter, supported by the full availability of the Muskrat Falls generating units. Delivery of the Nova Scotia Block commenced in August 2021, with the first physical delivery taking place on August 17, 2021.[18] Delivery of Supplemental Energy[19] commenced in November, with the first physical delivery taking place on November 1, 2021, and ceased on April 1, 2022. As per the Energy and Capacity Agreement, in instances where the LIL is fully unavailable, Hydro is not obligated to deliver the Nova Scotia Block or Supplemental Energy. In instances where the LIL is partially available, the Nova Scotia Block and Supplemental Energy are delivered on a *pro-rata* basis.

[14] Happy-Valley Gas Turbine ("Happy-Valley GT").
[15] Stephenville Gas Turbine ("Stephenville GT").
[16] Hardwoods Gas Turbine ("Hardwoods GT").
[17] In 2021, the monopole FOR was assumed to be 10% for each pole and was maintained through 2022. The FOR assumption decreases to 5.0% in 2023, 2.5% in 2024, and 1.0% per pole in 2025. It is assumed that the LIL would reach its design criteria FOR of 0.556% per pole in 2026.
[18] Pursuant to the Energy and Capacity Agreement between Nalcor Energy and Emera Inc., the Nova Scotia Block is a firm annual commitment of 980 GWh, supplied from the Muskrat Falls Hydroelectric Generating Facility on peak.
[19] Supplemental Energy is an amount of energy delivered to Emera in equal annual amounts over each of the first five years of operation of the Muskrat Falls Generating Station during the months of January to March and November to December during off-peak hours.

For units not owned by Hydro, the FORs used in modelling are determined using industry averages provided in the CEA Generating Equipment Reliability Information System and the NERC Generating Availability Data System. FORs used for assets owned by a third party in this analysis are presented in Table 2.

Table 2: Forced Outage Rates for Third-Party-Owned Assets

Asset	Reliability Metric
Hydraulic Units	DAFOR = 6.0%
Gas Turbines	DAUFOP = 6.3%
Corner Brook Cogen	DAUFOP = 20.1%

Hydro models wind generation stochastically using probability distribution functions developed for summer and winter generation at each of the Fermeuse and St. Lawrence Generating Facilities.

Import scenarios are contemplated as sensitivities to cases considered in this report; that is firm imports of 50 MW and 100 MW from December to March in winters where the LIL is assumed to be unavailable, with an associated FOR intended to serve as proxy for anticipated potential interruptions to the import. Since the availability of these contracts requires a counterparty 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.

3.3 Asset Retirement Plans

3.3.1 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 470 MW.[20] In advance of its planned retirement as a generating facility, the Holyrood TGS continues to be fully operational. Hydro has always intended to maintain up to a two-year period of standby operation of the Holyrood TGS during early operation of the Muskrat Falls Project assets. During this period of standby, the Holyrood TGS units would be fully available for generation. In correspondence dated February 4, 2022,[21] Hydro advised the Board of an

[20] Holyrood Unit 2 capacity has been reduced from 170 MW to 150 MW, as noted in the "Monthly Energy Supply Report for the Island Interconnected System for January 2022," Newfoundland and Labrador Hydro, February 17, 2022, s. 5.0, p. 4.
[21] "Reliability and Resource Adequacy Study Review – Additional Considerations of the Labrador-Island Reliability Assessment and Outcomes of the Failure Investigations Findings – Additional Information," Newfoundland and Labrador Hydro, February 4, 2022.

extension to the operations of the Holyrood TGS as a generating facility to March 31, 2024. Beyond the retirement 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. For the purposes of this analysis, in the scenarios where the LIL remains unavailable throughout the study period (2022–2025), the Holyrood TGS is assumed to be available for the entirety of the study period.

3.3.2 Hardwoods and Stephenville Gas Turbines

The 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.

As identified in the most recent transmission planning assessment,[22] following the retirement of the Stephenville GT, the backup supply for the area will be addressed by the addition of a 230/66 kV, 40/53.3/66.7 MVA power transformer at the Bottom Brook Terminal Station and subsequent reconfiguration at Stephenville Terminal Station. This addition will provide capacity via the 66 kV network in the event of the loss of the existing 230/66 kV transformer T3 at the Stephenville Terminal Station or the loss of the 230 kV transmission line TL209. This project was included in Hydro's 2021 Capital Budget Application.[23] Once the reconfiguration portion of the capital project is complete, the Stephenville GT will no longer be able to support the system as a generating unit. As this project will take two years to complete, the Stephenville GT is currently planned to be retired following completion of this project in August 2023, as it would no longer be available to support system requirements.[24]

With respect to the Hardwoods GT, operating hours and generation at this facility has decreased materially from levels observed in 2014 through 2018 and asset availability at these facilities is much improved over levels previously observed.[25]

[22] The 2020 Final Annual Planning Assessment was posted to the NLSO OASIS site on May 7, 2020.
[23] "2021 Capital Budget Application," Newfoundland and Labrador Hydro, rev. 2, November 2, 2020 (originally filed August 4, 2020).
[24] A fully established LIL is also a prerequisite for the retirement of the Stephenville GT.
[25] This reduction in the requirement to operate is primarily attributed to the high degree of reliability observed at the Holyrood TGS, the availability of the Maritime Link, and Hydro's ability to use a portion of the capacity available under its Capacity Assistance agreement with Corner Brook Pulp and Paper Limited ("CBPP") as ten-minute reserve.

Given continued uncertainty regarding the reliable in-service of the LIL, there is potential for Hydro to retain both the Hardwoods GT and the Stephenville GT in service until the LIL is proven reliable. In instances where Hydro models these units as continuing to be in service, it will continue to model these assets with a DAUFOP of 30% to ensure there is not an overreliance on these assets in the near term to maintain the reliability of the system. To ensure an appropriate balance of cost and reliability in this matter, Hydro will undertake necessary preventive and corrective maintenance work to ensure these units are available to the Island Interconnected System. However, Hydro will re-evaluate the decision to retain all or portions of the assets in service should extensive maintenance or incremental capital expenditures are required to facilitate this life extension.

In scenarios where it is assumed that the LIL will not be available through the study period (2022–2025), both the Hardwoods GT and Stephenville GT are assumed to remain in service through the study period.

4.0 Load Forecast

4.1 Load Forecasting

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. The load forecast is segmented by the Island Interconnected System and Labrador Interconnected System, rural isolated systems, as well as by utility load and industrial load. The load forecast process entails translating an economic and energy price forecast for the province into corresponding electric demand and energy requirements for the electric power systems. For the current analysis, Hydro has updated its provincial load forecast outlook to reflect the latest available load forecast information for its industrial customers, Newfoundland Power Inc., and Hydro's own rural service territories.

4.2 Forecast Load Requirements

The customer load requirement component of Hydro's near-term load forecast remains consistent with that used in Hydro's November Report. Hydro anticipates updating its forecast load requirements in spring 2022. The revised load forecast is anticipated to be the basis of Hydro's August 2022 Reliability and Resource Adequacy filing and the November 2022 report on near-term reliability, which will be prepared in advance of the 2022–2023 winter operating season. Hydro's near-term Labrador Interconnected System load forecast continues to reflect the unresolved power supply constraints to the western Labrador system, which are anticipated to be addressed through the ongoing implementation of the Network Additions Policy.

The demand forecasts by system are provided in Table 3 to Table 5.

Table 3: Island Interconnected System Peak Demand Forecast (MW)[26]

	2022	2023	2024	2025
Utility	1,474	1,473	1,478	1,481
Industrial Customer	154	162	179	180
Island Interconnected System Customer Coincident Demand	**1,627**	**1,635**	**1,656**	**1,661**
Island Interconnected System Transmission Losses and Station Service	75	100	100	100
Total Island Interconnected System Demand	**1,702**	**1,735**	**1,756**	**1,761**

Table 4: Labrador Interconnected System Peak Demand Forecast (MW)[27]

	2022	2023	2024	2025
Utility	146	140	141	142
Industrial Customer	308	308	308	308
Labrador Interconnected System Customer Coincident Demand	**453**	**448**	**449**	**450**
Labrador Interconnected System Transmission Losses and Station Service	27	27	27	27
Total Labrador Interconnected System Demand[28]	**480**	**475**	**476**	**477**

Table 5: Newfoundland and Labrador Interconnected System Peak Demand Forecast (MW)

	2022	2023	2024	2025
Newfoundland and Labrador Interconnected System Customer Coincident Demand	2,046	2,049	2,071	2,076
Newfoundland and Labrador Interconnected System Transmission Losses and Station Service	100	125	125	125
Total Newfoundland and Labrador Interconnected System Demand	**2,146**	**2,174**	**2,196**	**2,201**

[26] Numbers may not add due to rounding.
[27] Numbers may not add due to rounding.
[28] Overall peak load requirements for the Labrador Interconnected System are less than the total available generation capacity from the Recall and Twin Power Falls Corporation blocks (approximately 532 MW).

5.0 System Energy Capability

In order to reliably serve its customers, Hydro maintains minimum storage limits to ensure that it is capable of meeting customer energy requirements. In the current system, these limits represent the point at which Holyrood TGS generation would be required to be maximized to ensure Hydro could continue to meet customer requirements in consideration of the historical dry sequence. This year the limits include a conservative estimate of LIL energy delivered to the Island Interconnected System in consideration of ongoing commissioning activities through 2022. The limits do not consider the availability of imports over the Maritime Link, though imports can provide an additional opportunity to supplement energy in storage and economically reduce the amount of thermal generation required to maintain sufficient energy in storage. Regular assessments of storage at a reservoir level basis are also completed to ensure that each hydraulic generating unit remains capable of producing at full rated output through the winter period. The minimum storage limits are established to the end of April 2022. The remaining 2022 limits will be established following the freshet.

System energy in storage remained well above the minimum storage target throughout the 2021–2022 winter operating season. At the end of April 30, 2022, the total system energy in storage was 2,328 GWh, 2,108 GWh above the minimum storage limit of 220 GWh for April 2022.

Figure 1 plots the 2022 and 2021 storage levels, maximum operating level storage, and the 20-year average aggregate storage for comparison.

The third snow survey of 2022 was completed in mid-April 2022. Snow pack data was not collected in the Lower Salmon, Upper Salmon, Grey River, Granite Lake, and Victoria Lake regions since the snow pack was observed to be substantially depleted in those areas. Based on the available data, the survey indicated that, for the system as a whole, snow water equivalent was approximately 42% of average and equivalent energy was approximately 53% of average.[29] The snowpack represented approximately 75 mm of snow water equivalent for the Hinds Lake watershed and approximately 374 mm for the Cat Arm watershed. Spring freshet continues at Cat Arm and is expected to continue through May.

[29] Although the snow water equivalent values and therefore equivalent energy were below average relative to historical snow pack, there was the combination of rain and warm temperatures through winter 2021–2022 resulted in periods of snowmelt throughout the winter, compounded by an early start to spring freshet. The below average snow pack does not pose a concern as total system energy in storage is very high.

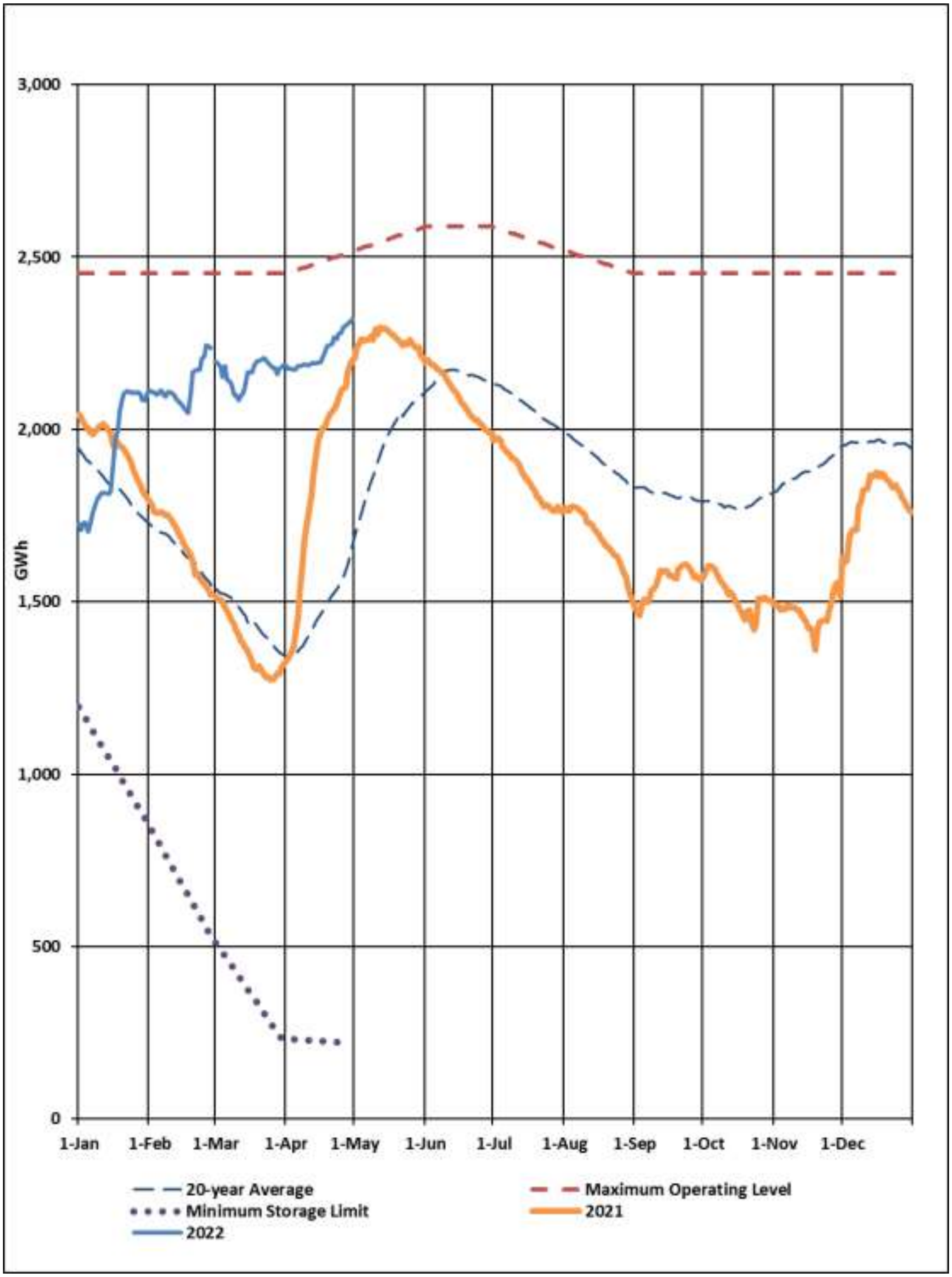

Figure 1: Total System Energy Storage for April 30, 2022

6.0 Results

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

6.1 Scenario Analysis

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

- **Scenario 1:** Assumes that the LIL will be available at 450 MW until January 2023 and at full capacity in January 2023. This case assumes a DAFOR of 15% for the Holyrood TGS as well as the retirement of the Holyrood TGS, Hardwoods GT, and Stephenville GT on March 31, 2024.
- **Scenario 2:** Varies from Scenario 1 by increasing the Holyrood TGS DAFOR to 20%.
- **Scenario 3:** Varies from Scenario 1 by increasing the Holyrood TGS DAFOR to the 2021 actual DAFOR of 34%.
- **Scenario 4:** Varies from Scenario 1 by retiring the Stephenville GT on August 31, 2023.
- **Scenario 5:** Varies from Scenario 1 by assuming that the LIL is not available through the study period (2022–2025). The operation of Holyrood TGS, Hardwoods GT, and Stephenville GT is extended through the study period at baseline FORs.
- **Scenario 6:** Varies from Scenario 5 by increasing the Holyrood TGS DAFOR to 20%.
- **Scenario 7:** Varies from Scenario 5 by increasing the Holyrood TGS DAFOR to the 2021 actual DAFOR of 34%.
- **Scenario 8:** Varies from Scenario 5 by retiring the Stephenville GT on August 31, 2023.
- **Scenario 9:** Varies from Scenario 6 by including 50 MW of imports during peak hours during the winter season.
- **Scenario 10:** Varies from Scenario 6 by including 100 MW of imports during peak hours during the winter season.

For Scenarios 5–10, it is assumed that the contract for capacity assistance with Vale is renewed for each winter season in the study period.

For CBPP Capacity Assistance, the existing agreement is in place until spring 2023. In Scenarios 1–4, this remains unchanged. In Scenarios 5–10, it is assumed that the CBPP Capacity Assistance remains in place throughout the study period.

6.2 Expected Unserved Energy and Loss of Load Hours Analysis

Sections 6.2.1 and 6.2.2 provide the results of the annual and monthly analysis, respectively.

6.2.1 Annual Assessment Results

Table 6 provides the annual LOLH, EUE and NEUE 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 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, the Hardwoods GT, and the Stephenville GT has 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 6: Annual LOLH, EUE, and NEUE Results

LOLH (hours)	2022	2023	2024	2025
Scenario 1: LIL at 450 MW to January 2023, Holyrood TGS DAFOR = 15%	0.03	0.01	0.28	0.38
Scenario 2: LIL at 450 MW to January 2023, Holyrood TGS DAFOR = 20%	0.07	0.02	0.27	N/A
Scenario 3: LIL at 450 MW to January 2023, Holyrood TGS DAFOR = 34%	0.22	0.06	0.27	N/A
Scenario 4: LIL at 450 MW to January 2023, Stephenville GT retired in 2023, Holyrood TGS DAFOR = 15%	0.03	0.01	0.27	N/A
Scenario 5: No LIL, Holyrood TGS, Stephenville GT, and Hardwoods GT extended to 2025, Holyrood TGS DAFOR = 15%	1.74	1.94	2.89	3.19
Scenario 6: No LIL, Holyrood TGS, Stephenville GT, and Hardwoods GT extended to 2025, Holyrood TGS DAFOR = 20%	3.24	3.63	5.24	5.78
Scenario 7: No LIL, Holyrood TGS, Stephenville GT, and Hardwoods GT extended to 2025, Holyrood TGS DAFOR = 34%	11.46	12.65	17.06	18.94
Scenario 8: No LIL, Holyrood TGS and Hardwoods GT extended to 2025, Stephenville GT retired in 2023, Holyrood TGS DAFOR = 15%	1.74	2.62	7.84	8.64
Scenario 9: No LIL, Holyrood TGS, Stephenville GT, and Hardwoods GT extended to 2025, Holyrood TGS DAFOR = 20%, 50 MW imports	1.66	1.87	2.86	3.12
Scenario 10: No LIL, Holyrood TGS, Stephenville GT, and Hardwoods GT extended to 2025, Holyrood TGS DAFOR = 20%, 100 MW imports	0.86	0.95	1.53	1.69

EUE (MWh)	2022	2023	2024	2025
Scenario 1: LIL at 450 MW to January 2023, Holyrood TGS DAFOR = 15%	2	1	24	37
Scenario 2: LIL at 450 MW to January 2023, Holyrood TGS DAFOR = 20%	4	1	24	N/A
Scenario 3: LIL at 450 MW to January 2023, Holyrood TGS DAFOR = 34%	13	4	24	N/A
Scenario 4: LIL at 450 MW to January 2023, Stephenville GT retired in 2023, Holyrood TGS DAFOR = 15%	2	1	24	N/A
Scenario 5: No LIL, Holyrood TGS, Stephenville GT, and Hardwoods GT extended to 2025, Holyrood TGS DAFOR = 15%	94	105	163	179
Scenario 6: No LIL, Holyrood TGS, Stephenville GT, and Hardwoods GT extended to 2025, Holyrood TGS DAFOR = 20%	181	206	309	344
Scenario 7: No LIL, Holyrood TGS, Stephenville GT, and Hardwoods GT extended to 2025, Holyrood TGS DAFOR = 34%	693	774	1106	1222
Scenario 8: No LIL, Holyrood TGS and Hardwoods GT extended to 2025, Stephenville GT retired in 2023, Holyrood TGS DAFOR = 15%	94	144	478	522
Scenario 9: No LIL, Holyrood TGS, Stephenville GT, and Hardwoods GT extended to 2025, Holyrood TGS DAFOR = 20%, 50 MW imports	85	97	158	171
Scenario 10: No LIL, Holyrood TGS, Stephenville GT, and Hardwoods GT extended to 2025, Holyrood TGS DAFOR = 20%, 100 MW imports	42	47	76	90

NEUE (ppm)[30]	2022	2023	2024	2025
Scenario 1: LIL at 450 MW to January 2023, Holyrood TGS DAFOR = 15%	0.21	0.07	2.91	4.46
Scenario 2: LIL at 450 MW to January 2023, Holyrood TGS DAFOR = 20%	0.48	0.17	2.90	N/A
Scenario 3: LIL at 450 MW to January 2023, Holyrood TGS DAFOR = 34%	1.53	0.47	2.82	N/A
Scenario 4: LIL at 450 MW to January 2023, Stephenville GT retired in 2023, Holyrood TGS DAFOR = 15%	0.21	0.08	2.81	N/A
Scenario 5: No LIL, Holyrood TGS, Stephenville GT, and Hardwoods GT extended to 2025, Holyrood TGS DAFOR = 15%	10.79	12.08	18.47	20.36
Scenario 6: No LIL, Holyrood TGS, Stephenville GT, and Hardwoods GT extended to 2025, Holyrood TGS DAFOR = 20%	20.79	23.76	35.05	38.98
Scenario 7: No LIL, Holyrood TGS, Stephenville GT, and Hardwoods GT extended to 2025, Holyrood TGS DAFOR = 34%	79.81	89.31	125.51	138.54
Scenario 8: No LIL, Holyrood TGS and Hardwoods GT extended to 2025, Stephenville GT retired in 2023, Holyrood TGS DAFOR = 15%	10.79	16.61	54.22	59.18
Scenario 9: No LIL, Holyrood TGS, Stephenville GT, and Hardwoods GT extended to 2025, Holyrood TGS DAFOR = 20%, 50 MW imports	9.77	11.11	17.86	19.37
Scenario 10: No LIL, Holyrood TGS, Stephenville GT, and Hardwoods GT extended to 2025, Holyrood TGS DAFOR = 20%, 100 MW imports	4.80	5.38	8.59	10.14

[30] NEUE, given here in ppm, represents lost load as a fraction of total system load. NERC recommends system operators consider NEUE a reliability metric, but a single target threshold has not been set. Different jurisdictions use targets ranging from 10 to 30 ppm.

The results of Scenarios 1–4 indicate that the availability of the LIL at partial capability, backed up by the Holyrood TGS mitigates the risk of lost load and unserved energy in the near term. Once the Holyrood TGS is retired, higher levels of LOLH and EUE are observed, but levels remain within planning criteria.

The results of Scenario 3 indicate that if Holyrood is serving as a backup facility and the LIL is available to offset Holyrood requirements, there is no material risk to system reliability in the near term at the higher DAFOR value observed in 2021. However, the results of Scenario 7 demonstrate that if the LIL becomes unavailable through the study period concurrent with a high degree of unavailability at the Holyrood TGS, there is a considerable amount of system risk present. These results support continued, measured investment to maintain Holyrood TGS as a reliable generation station in the near term.

The results of Scenarios 5–7 indicate that if the LIL is fully unavailable during the winter operating season, both LOLH and EUE grow as the unavailability of Holyrood TGS increases.

The results of Scenario 4 indicates that in instances where the LIL is available at 450 MW, the Stephenville GT can otherwise be retired as planned. However, as observed in the results for Scenario 8, in instances where the LIL is not available, the concurrent unavailability of the Stephenville GT materially increases the level of system risk observed.

As such, it can be observed that there is an increased risk of generation shortfall until the LIL is reliably in service, with the amount of risk highly dependent on the availability of the Holyrood TGS.[31] Given the uncertainty around the reliability and availability of the LIL, it is also recommended that measures be taken to maintain the capability of the Stephenville GT as a generating unit, to be retired on the same schedule as the Holyrood TGS.[32] Finally, as demonstrated in Scenarios 9 and 10, imports over the Maritime Link could be used to mitigate the risk of generation shortfall in the event of a high degree of unreliability at the Holyrood TGS. An import of 50 MW in the on-peak 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.

[31] For reference, the weighted average thermal DAFOR for 12 months ending September 2021 was 12.28% as reported in the "Quarterly Report on Performance of Generating Units for the Quarter Ended September 30, 2021," Newfoundland and Labrador Hydro, October 29, 2021.
[32] This will require the reconfiguration phase of the project that is currently scheduled for August 2023 to be delayed until after winter 2024.

6.2.2 Monthly Assessment Results

Table 7 to Table 10 provides 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.

In Scenarios 1–4, the availability of the LIL at partial capability, backed up by the Holyrood TGS mitigates the risk of lost load and unserved energy. Fall 2024 continues to have higher levels of LOLH and EUE, however improvements are evident on a monthly basis once the FOR is reduced to 1% per pole on January 1, 2025. Finally, it is noted that further reductions in LOLH and EUE are anticipated in 2026 once the LIL is assumed to reach its design criteria FOR of 0.556% per pole.

The results of Scenarios 5–7 indicate that if the LIL is fully unavailable during the winter operating season, both LOLH and EUE grow as the unavailability of Holyrood TGS increases.

As evident in Scenario 8, the extension of operation of Stephenville GT as a generating unit materially reduces the amount of system risk present in the event the LIL remains unavailable through the study period. Finally, as seen in Scenarios 9 and 10, the import of firm energy over the Maritime Link produces a significant improvement in system reliability. This demonstrates that retention of Stephenville as a generation unit and the use of firm imports could mitigate the increased risk of resource shortfalls if the LIL is delayed or if it’s unavailability and/or reliability is worse than what is assumed in this analysis, or if the Holyrood TGS or other generating assets were to perform more poorly than the assumptions outlined in this analysis.

Table 7: Monthly LOLH and EUE for 2022[33]

LOLH (hours)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Scenario 1: LIL at 450 MW to January 2023, Holyrood TGS DAFOR = 15%	0.02	0.01	0	0	0	0	0	0	0	0	0	0
Scenario 2: LIL at 450 MW to January 2023, Holyrood TGS DAFOR = 20%	0.04	0.01	0	0	0	0	0	0	0	0	0	0.01
Scenario 3: LIL at 450 MW to January 2023, Holyrood TGS DAFOR = 34%	0.11	0.04	0.02	0	0	0	0	0	0	0	0	0.04
Scenario 4: LIL at 450 MW to January 2023, Stephenville GT retired in 2023, Holyrood TGS DAFOR = 15%[34]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Scenario 5: No LIL, Holyrood TGS, Stephenville GT, and Hardwoods GT extended to 2025, Holyrood TGS DAFOR = 15%	1.07	0.26	0.12	0	0	0	0	0	0	0	0	0.28
Scenario 6: No LIL, Holyrood TGS, Stephenville GT, and Hardwoods GT extended to 2025, Holyrood TGS DAFOR = 20%	1.91	0.52	0.25	0.01	0	0	0	0	0	0	0.01	0.54
Scenario 7: No LIL, Holyrood TGS, Stephenville GT, and Hardwoods GT extended to 2025, Holyrood TGS DAFOR = 34%	6.2	2.09	1.06	0.04	0	0	0	0	0	0	0.04	2.02
Scenario 8: No LIL, Holyrood TGS and Hardwoods GT extended to 2025, Stephenville GT retired in 2023, Holyrood TGS DAFOR = 15%[35]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Scenario 9: No LIL, Holyrood TGS, Stephenville GT, and Hardwoods GT extended to 2025, Holyrood TGS DAFOR = 20%, 50 MW imports	1.02	0.24	0.12	0	0	0	0	0	0	0	0.01	0.27
Scenario 10: No LIL, Holyrood TGS, Stephenville GT, and Hardwoods GT extended to 2025, Holyrood TGS DAFOR = 20%, 100 MW imports	0.54	0.54	0.12	0.01	0	0	0	0	0	0	0.01	0.13

EUE (MWh)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Scenario 1: LIL at 450 MW to January 2023, Holyrood TGS DAFOR = 15%	1	0	0	0	0	0	0	0	0	0	0	0
Scenario 2: LIL at 450 MW to January 2023, Holyrood TGS DAFOR = 20%	3	1	0	0	0	0	0	0	0	0	0	1
Scenario 3: LIL at 450 MW to January 2023, Holyrood TGS DAFOR = 34%	7	2	1	0	0	0	0	0	0	0	0	3
Scenario 4: LIL at 450 MW to January 2023, Stephenville GT retired in 2023, Holyrood TGS DAFOR = 15%[31]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Scenario 5: No LIL, Holyrood TGS, Stephenville GT, and Hardwoods GT extended to 2025, Holyrood TGS DAFOR = 15%	61	12	6	0	0	0	0	0	0	0	0	15
Scenario 6: No LIL, Holyrood TGS, Stephenville GT, and Hardwoods GT extended to 2025, Holyrood TGS DAFOR = 20%	113	26	12	0	0	0	0	0	0	0	0	29

[33] Monthly results may not add up to annual results due to rounding.
[34] In 2022, Scenario 4 is the same as Scenario 1.
[35] In 2022, Scenario 8 is the same as Scenario 5.

EUE (MWh)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Scenario 7: No LIL, Holyrood TGS, Stephenville GT, and Hardwoods GT extended to 2025, Holyrood TGS DAFOR = 34%	411	107	52	2	0	0	0	0	0	0	2	120
Scenario 8: No LIL, Holyrood TGS and Hardwoods GT extended to 2025, Stephenville GT retired in 2023, Holyrood TGS DAFOR = 15%[36]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Scenario 9: No LIL, Holyrood TGS, Stephenville GT, and Hardwoods GT extended to 2025, Holyrood TGS DAFOR = 20%, 50 MW imports	56	11	5	0	0	0	0	0	0	0	0	12
Scenario 10: No LIL, Holyrood TGS, Stephenville GT, and Hardwoods GT extended to 2025, Holyrood TGS DAFOR = 20%, 100 MW imports	28	5	2	0	0	0	0	0	0	0	0	6

Table 8: Monthly LOLH and EUE for 2023

LOLH (hours)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Scenario 1: LIL at 450 MW to January 2023, Holyrood TGS DAFOR = 15%	0	0	0	0	0	0	0	0	0	0	0	0
Scenario 2: LIL at 450 MW to January 2023, Holyrood TGS DAFOR = 20%	0.01	0.01	0	0	0	0	0	0	0	0	0	0
Scenario 3: LIL at 450 MW to January 2023, Holyrood TGS DAFOR = 34%	0.03	0.01	0.01	0	0	0	0	0	0	0	0	0.01
Scenario 4: LIL at 450 MW to January 2023, Stephenville GT retired in 2023, Holyrood TGS DAFOR = 15%	0	0	0	0	0	0	0	0	0	0	0	0
Scenario 5: No LIL, Holyrood TGS, Stephenville GT, and Hardwoods GT extended to 2025, Holyrood TGS DAFOR = 15%	1.11	0.34	0.14	0	0	0	0	0	0	0	0	0.34
Scenario 6: No LIL, Holyrood TGS, Stephenville GT, and Hardwoods GT extended to 2025, Holyrood TGS DAFOR = 20%	1.98	0.67	0.30	0.01	0	0	0	0	0	0	0.01	0.66
Scenario 7: No LIL, Holyrood TGS, Stephenville GT, and Hardwoods GT extended to 2025, Holyrood TGS DAFOR = 34%	6.41	2.60	1.23	0.05	0	0	0	0	0	0	0.05	2.29
Scenario 8: No LIL, Holyrood TGS and Hardwoods GT extended to 2025, Stephenville GT retired in 2023, Holyrood TGS DAFOR = 15%	1.11	0.34	0.14	0	0	0	0	0	0	0	0.02	1.00
Scenario 9: No LIL, Holyrood TGS, Stephenville GT, and Hardwoods GT extended to 2025, Holyrood TGS DAFOR = 20%, 50 MW imports	1.07	0.31	0.15	0.01	0	0	0	0	0	0	0.01	0.31
Scenario 10: No LIL, Holyrood TGS, Stephenville GT, and Hardwoods GT extended to 2025, Holyrood TGS DAFOR = 20%, 100 MW imports	0.55	0.15	0.07	0.01	0	0	0	0	0	0	0.01	0.15

[36] In 2022, Scenario 8 is the same as Scenario 5.

EUE (MWh)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Scenario 1: LIL at 450 MW to January 2023, Holyrood TGS DAFOR = 15%	0	0	0	0	0	0	0	0	0	0	0	0
Scenario 2: LIL at 450 MW to January 2023, Holyrood TGS DAFOR = 20%	1	0	0	0	0	0	0	0	0	0	0	0
Scenario 3: LIL at 450 MW to January 2023, Holyrood TGS DAFOR = 34%	2	1	0	0	0	0	0	0	0	0	0	1
Scenario 4: LIL at 450 MW to January 2023, Stephenville GT retired in 2023, Holyrood TGS DAFOR = 15%	0	0	0	0	0	0	0	0	0	0	0	0
Scenario 5: No LIL, Holyrood TGS, Stephenville GT, and Hardwoods GT extended to 2025, Holyrood TGS DAFOR = 15%	62	17	6	0	0	0	0	0	0	0	0	19
Scenario 6: No LIL, Holyrood TGS, Stephenville GT, and Hardwoods GT extended to 2025, Holyrood TGS DAFOR = 20%	119	34	15	0	0	0	0	0	0	0	1	37
Scenario 7: No LIL, Holyrood TGS, Stephenville GT, and Hardwoods GT extended to 2025, Holyrood TGS DAFOR = 34%	430	139	62	2	0	0	0	0	0	0	2	138
Scenario 8: No LIL, Holyrood TGS and Hardwoods GT extended to 2025, Stephenville GT retired in 2023, Holyrood TGS DAFOR = 15%	62	17	6	0	0	0	0	0	0	0	1	58
Scenario 9: No LIL, Holyrood TGS, Stephenville GT, and Hardwoods GT extended to 2025, Holyrood TGS DAFOR = 20%, 50 MW imports	57	15	8	1	0	0	0	0	0	0	0	16
Scenario 10: No LIL, Holyrood TGS, Stephneville GT, and Hardwoods GT extended to 2025, Holyrood TGS DAFOR = 20%, 100 MW imports	29	6	3	1	0	0	0	0	0	0	0	8

Table 9: Monthly LOLH and EUE for 2024

LOLH (hours)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Scenario 1: LIL at 450 MW to January 2023, Holyrood TGS DAFOR = 15%	0	0	0	0.01	0	0	0	0	0	0	0.05	0.20
Scenario 2: LIL at 450 MW to January 2023, Holyrood TGS DAFOR = 20%	0	0	0	0.01	0.01	0	0	0	0	0	0.06	0.20
Scenario 3: LIL at 450 MW to January 2023, Holyrood TGS DAFOR = 34%	0.01	0	0	0.01	0	0	0	0	0	0	0.05	0.18
Scenario 4: LIL at 450 MW to January 2023, Stephenville GT retired in 2023, Holyrood TGS DAFOR = 15%	0	0	0	0.01	0	0	0	0	0	0	0.06	0.20
Scenario 5: No LIL, Holyrood TGS, Stephenville GT, and Hardwoods GT extended to 2025, Holyrood TGS DAFOR = 15%	1.78	0.42	0.25	0.01	0	0	0	0	0	0	0.02	0.40
Scenario 6: No LIL, Holyrood TGS, Stephenville GT, and Hardwoods GT extended to 2025, Holyrood TGS DAFOR = 20%	3.12	0.81	0.47	0.02	0	0	0	0	0	0	0.05	0.76
Scenario 7: No LIL, Holyrood TGS, Stephenville GT, and Hardwoods GT extended to 2025, Holyrood TGS DAFOR = 34%	9.26	3.05	1.84	0.1	0	0	0	0	0	0	0.22	2.56
Scenario 8: No LIL, Holyrood TGS and Hardwoods GT extended to 2025, Stephenville GT retired in 2023, Holyrood TGS DAFOR = 15%	4.53	1.26	0.76	0.04	0	0	0	0	0	0	0.08	1.16

LOLH (hours)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Scenario 9: No LIL, Holyrood TGS, Stephenville GT, and Hardwoods GT extended to 2025, Holyrood TGS DAFOR = 20%, 50 MW imports	1.72	0.45	0.21	0.02	0	0	0	0	0	0	0.06	0.40
Scenario 10: No LIL, Holyrood TGS, Stephenville GT, and Hardwoods GT extended to 2025, Holyrood TGS DAFOR = 20%, 100 MW imports	0.91	0.2	0.1	0.02	0	0	0	0	0	0	0.07	0.22

EUE (MWh)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Scenario 1: LIL at 450 MW to January 2023, Holyrood TGS DAFOR = 15%	0	0	0	0	0	0	0	0	0	0	4	19
Scenario 2: LIL at 450 MW to January 2023, Holyrood TGS DAFOR = 20%	0	0	0	0	0	0	0	0	0	0	4	19
Scenario 3: LIL at 450 MW to January 2023, Holyrood TGS DAFOR = 34%	1	0	0	0	0	0	0	0	0	0	4	18
Scenario 4: LIL at 450 MW to January 2023, Stephenville GT retired in 2023, Holyrood TGS DAFOR = 15%	0	0	0	0	0	0	0	0	0	0	4	19
Scenario 5: No LIL, Holyrood TGS, Stephenville GT, and Hardwoods GT extended to 2025, Holyrood TGS DAFOR = 15%	105	23	11	0	0	0	0	0	0	0	1	23
Scenario 6: No LIL, Holyrood TGS, Stephenville GT, and Hardwoods GT extended to 2025, Holyrood TGS DAFOR = 20%	196	44	23	1	0	0	0	0	0	0	2	43
Scenario 7: No LIL, Holyrood TGS, Stephenville GT, and Hardwoods GT extended to 2025, Holyrood TGS DAFOR = 34%	658	175	96	4	0	0	0	0	0	0	10	163
Scenario 8: No LIL, Holyrood TGS and Hardwoods GT extended to 2025, Stephenville GT retired in 2023, Holyrood TGS DAFOR = 15%	294	70	39	2	0	0	0	0	0	0	4	68
Scenario 9: No LIL, Holyrood TGS, Stephenville GT, and Hardwoods GT extended to 2025, Holyrood TGS DAFOR = 20%, 50 MW imports	101	22	9	1	0	0	0	0	0	0	2	22
Scenario 10: No LIL, Holyrood TGS, Stephenville GT, and Harwoods GT extended to 2025, Holyrood TGS DAFOR = 20%, 100 MW imports	49	9	4	1	0	0	0	0	0	0	3	11

Table 10: Monthly LOLH and EUE for 2025

LOLH (hours)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Scenario 1: LIL at 450 MW to January 2023, Holyrood TGS DAFOR = 15%	0.16	0.08	0.05	0.01	0	0	0	0	0	0	0.01	0.06
Scenario 2: LIL at 450 MW to January 2023, 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
Scenario 3: LIL at 450 MW to January 2023, Holyrood TGS DAFOR = 34%	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Scenario 4: LIL at 450 MW to January 2023, Stephenville GT retired in 2023, 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
Scenario 5: No LIL, Holyrood TGS, Stephenville GT, and Hardwoods GT extended to 2025, Holyrood TGS DAFOR = 15%	1.91	0.52	0.25	0.01	0	0	0	0	0	0	0.03	0.46

LOLH (hours)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Scenario 6: No LIL, Holyrood TGS, Stephenville GT, and Hardwoods GT extended to 2025, Holyrood TGS DAFOR = 20%	3.28	1.04	0.5	0.02	0	0	0	0	0	0	0.06	0.87
Scenario 7: No LIL, Holyrood TGS, Stephenville GT, and Hardwoods GT extended to 2025, Holyrood TGS DAFOR = 34%	9.87	3.74	2	0.09	0.01	0	0	0	0	0.01	0.28	2.95
Scenario 8: No LIL, Holyrood TGS and Hardwoods GT extended to 2025, Stephenville GT retired in 2023, Holyrood TGS DAFOR = 15%	4.85	1.55	0.8	0.04	0	0	0	0	0	0	0.09	1.31
Scenario 9: No LIL, Holyrood TGS, Stephenville GT, and Hardwoods GT extended to 2025, Holyrood TGS DAFOR = 20%, 50 MW imports	1.84	0.5	0.23	0.02	0	0	0	0	0	0	0.07	0.46
Scenario 10: No LIL, Holyrood TGS, Stephenville GT, and Hardwoods GT extended to 2025, Holyrood TGS DAFOR = 20%, 100 MW imports	1.01	0.24	0.11	0.03	0	0	0	0	0	0	0.06	0.24

EUE (MWh)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Scenario 1: LIL at 450 MW to January 2023, Holyrood TGS DAFOR = 15%	16	8	5	1	0	0	0	0	0	0	1	6
Scenario 2: LIL at 450 MW to January 2023, 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
Scenario 3: LIL at 450 MW to January 2023, Holyrood TGS DAFOR = 34%	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Scenario 4: LIL at 450 MW to January 2023, Stephenville GT retired in 2023, 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
Scenario 5: No LIL, Holyrood TGS, Stephenville GT, and Hardwoods GT extended to 2025, Holyrood TGS DAFOR = 15%	113	27	12	0	0	0	0	0	0	0	1	26
Scenario 6: No LIL, Holyrood TGS, Stephenville GT, and Hardwoods GT extended to 2025, Holyrood TGS DAFOR = 20%	208	56	24	1	0	0	0	0	0	0	3	51
Scenario 7: No LIL, Holyrood TGS, Stephenville GT, and Hardwoods GT extended to 2025, Holyrood TGS DAFOR = 34%	701	210	108	4	0	0	0	0	0	0	12	187
Scenario 8: No LIL, Holyrood TGS and Hardwoods GT extended to 2025, Stephenville GT retired in 2023, Holyrood TGS DAFOR = 15%	311	85	42	2	0	0	0	0	0	0	5	78
Scenario 9: No LIL, Holyrood TGS, Stephenville GT, and Hardwoods GT extended to 2025, Holyrood TGS DAFOR = 20%, 50 MW imports	110	23	11	1	0	0	0	0	0	0	3	24
Scenario 10: No LIL, Holyrood TGS, Stephenville GT, and Hardwoods GT extended to 2025, Holyrood TGS DAFOR = 20%, 100 MW imports	57	11	5	1	0	0	0	0	0	0	3	13

7.0 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 The Liberty Consulting Group, the availability of power over the LIL remains essential to system reliability in the near term.

To help ensure reliable service for customers in advance of the in-service of the LIL, Hydro has committed to maintaining the Holyrood TGS as a generating facility until March 31, 2024. Hydro will inform the Board of any changes to this time frame as it continues to monitor LIL progress and schedules. As supported by the analysis in this report, Hydro recommends extending operation of both the Hardwoods GT and the Stephenville GT, retiring these assets at the same time as the Holyrood TGS. This would likely mean a modification or delay to the current plan for reconfiguration of the system in the Stephenville area following the installation of the power transformer at the Bottom Brook Terminal Station.

Hydro continues to closely monitor the reliability of the Lower Churchill Project assets, while carefully planning to ensure a reliable system for its customers in advance of the full, reliable in-service of the Muskrat Falls Project. In this analysis, Hydro has also presented results of system reliability metrics considering the assets: 1) in service as planned; 2) in service at levels that have already been demonstrated, and; 3) not in service, to ensure that it has a fulsome understanding of the resultant system reliability considering the full range of operating scenarios for the Muskrat Falls Project assets. Hydro continues 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. Hydro is also focused on the completion of its annual maintenance program to ensure the reliability of its existing assets and infrastructure in the near term.

Following the full in-service of the Muskrat Falls Project assets and the retirement of the 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 prior to the reliable in-service of the Muskrat Falls Project assets.