Reliability and Resource Adequacy Study 2021 Update

Volume II: Near-Term Reliability Report – May Report

May 17, 2020

A report to the Board of Commissioners of Public Utilities

newfoundland labrador hydro
a nalcor energy company

Contents

1.0 Introduction

Supply adequacy in advance of the availability of full production from the Muskrat Falls Generating Station ("Muskrat Falls GS") 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 of the Newfoundland and Labrador Interconnected System for the study period, a five-year horizon from 2021–2025, and provides the results of the probabilistic resource adequacy assessment for the Newfoundland and Labrador Interconnected System for the 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 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 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.

[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.

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 each of the next five years (2021–2025) 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 2020 Near-Term Reliability Report ("November Report"), Unit 1 at the Muskrat Falls GS has been released for service and progress has been made on the Labrador Island Link ("LIL"). Interim Bipole Trial Operations of the LIL began on March 19, 2021 and were successfully completed on May 1, 2021. During the trial operations period, the LIL was operated at various power transfer levels based on grid conditions. Maximum power transfer during the period was 225 MW, as per the Interim Bipole Software testing requirements. Power Supply continues to move towards implementation of Final Bipole Software and full commissioning of the Muskrat Falls project, expected in November 2021.

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. Given the completion of Interim Bipole Trial Operations it is likely that the LIL will be available for some level of power transfer throughout the 2021–2022 winter operating season; however, to provide a fulsome view of potential system reliability, 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.

Finally, Hydro has also included assessments of the increased level of reliability resulting from supplementing island supply with imports over the Maritime Link, as well as the implications of the potential continued closure of the North Atlantic Refining Limited ("NARL") oil refinery through the 2021–2022 winter operating season.

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"), with updates to reflect current system assumptions. A detailed discussion of the initial modelling approach used can be found in Volumes I and II of the 2018 Filing. 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," filed in November 2019 ("2019 Update"), and the "Near Term Reliability Report," filed on May 15, 2020 ("May Report").

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]

3.0 Asset Reliability

On a quarterly basis, reports are filed with the Board which include actual forced outage rates and their relation to:

- The rolling 12-month performance of its units;[4]
- Past historical rates; and
- Assumptions used in assessment of resource adequacy.

The most recent report was submitted on April 30, 2021, for the quarter ended March 31, 2021. 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.

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

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

[3] NLSO Standard "Transmission Planning Criteria Doc # TP-S-007," Newfoundland and Labrador Hydro, May 11, 2018.
[4] Quarterly Report on Performance of Generating Units.

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 Unit 1 Vibration, Bay d'Espoir Penstocks and Upper Salmon rotor rim key cracking) and ongoing (Granite Canal control system);
- Thermal Facilities: New (Water Treatment Plant – Low Feed Water Production, Power Centre C Failure), continued monitoring (boiler feed pump motor issues), ongoing [unit boiler tubes, variable frequency drives("VFD")]; and
- Gas Turbines: None noted.

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 Unit 1 Vibration

As previously reported, Bay d'Espoir Unit 1 was removed from service on May 31, 2020 to undergo its major preventative maintenance (PM9) overhaul. Following the return to service of the unit in July 2020 there was a noted increase in the generator vibration levels. This increase resulted in higher than normal vibration levels at loads between 55 and 65 MW.

Hydro completed a four-day outage on September 11, 2020 to investigate the vibration issue and determined that the generator guide bearing required adjustments to improve clearances. During this outage these adjustments were completed, critical clearance measurements were taken, and bolt torque was checked on embedded parts. Completion of these activities successfully reduced the vibration levels of the unit to an acceptable range allowing for the removal of the previously imposed operating restriction in the 55–65 MW load range.

Since filing the November Report Hydro has continued to monitor the trending data of Unit 1 and results illustrate that the vibration and temperature levels are stable and not increasing. Additionally, Unit 1 was removed from service on April 25, 2021 for its scheduled annual maintenance. Measurements confirm that generator guide bearing clearances remain acceptable. Further review is currently taking place during the Unit 1 scheduled annual maintenance with ongoing scope consisting of the comprehensive analysis of generator air gaps, seal clearances, runner elevations, bolt torques and oil analysis.

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.[5] In response to the most recent September 2019 failure of Penstock 1, SNC-Lavalin 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. The results of this failure analysis and engineering review were filed with the Board on June 3, 2020.[6] 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 scheduled for completion in the fourth quarter of 2021. The results of the FEED will detail an investment strategy plan for life extension activities related to all three Bay d'Espoir Penstocks.

To mitigate potential impacts should another leak in Penstock 1 occur, proactive measures have been taken to reduce 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. Modifications to the Automatic Generator Control application in Hydro's Energy Management System

[5] "Bay d'Espoir Level II Condition Assessment of Penstock No. 1, 2, and 3," Hatch Ltd., rev. 0, December 13, 2018; "Final Report for Condition Assessment and Refurbishment Options for Penstocks 1, 2 and 3," Hatch Ltd., rev. 0, March 28, 2019; and "Final Report for Penstock No.'s 1, 2 and 3 Life Extension Options," Hatch Ltd. rev. 0, July 26, 2019.
[6] "2019 Failure of Bay d'Espoir Penstock 1 and Plan Regarding Penstock Life Extension," Newfoundland and Labrador Hydro, June 3, 2020.

designed to limit the amount of rough zone operation have also been implemented for Units 1–6 at Bay d'Espoir. A more prescriptive operating regime has been implemented for Units 1 and 2 at Bay d'Espoir, given the condition 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.

As previously reported, the inspection of Penstock 3, which was originally scheduled for completion in May 2020, was deferred to 2021 due to limitations associated with the onset of the COVID-19 pandemic. This decision was made in consultation with the consultant responsible for the penstock inspections and it was determined that Penstock 3 is safe for continued operation until the next scheduled inspection in 2021. Penstock 3 was last inspected in April 2019. Penstock 1 was inspected in July 2020 and Penstock 2 in October 2020; the inspections did not identify any major defects or areas of concern.

The 2021 inspections for all three penstocks are scheduled for completion during the 2021 annual maintenance season. During the recently scheduled inspection of Penstock 1 in May 2021, 16 distinct cracks were identified over an approximately 200 foot span of the penstock with cracks ranging in length from a couple of inches to 8 feet. The cracks were similar in condition to those discovered in recent years and were shallow in depth. Weld refurbishment and final inspection has been completed and the penstock is being readied for return to service. This discovery was not unexpected given the known condition of the Bay d'Espoir Penstocks. Hydro will use the 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 later this year.

Upper Salmon Rotor Key Cracking

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 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. 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 since that time have revealed no new cracking. The decision has been made to extend the inspection interval to quarterly.

Granite Canal Control System

A thorough engineering assessment of the system, in response to control system malfunctions experienced when remotely starting and/or stopping the Granite Canal unit, has been completed. 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. Further investigation regarding the remaining useful life of the control system has also 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 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 are being procured in 2021.

3.1.2 Thermal

Water Treatment Plant – Low Feed Water Production

On December 22, 2020, Units 1, 2 and 3 were derated to 50 MW each and subsequently Unit 1 was shutdown for a period of time as a result of insufficient feed water to sustain generation. Hydro completed a TapRooT investigation of this incident to understand the cause and identify corrective actions to ensure that a repeat will not occur. The report was completed on March 16, 2021.

The investigation revealed a number of causal factors. These included extreme weather events (i.e., wind and rain) leading up to the incident, equipment issues (i.e., two air heater condensate pumps on Unit 1 were out of service due to failed seals), and procedural issues. Nine corrective actions were identified in the investigation and are being implemented this year. Many of these are focused on ensuring that sufficient checks of the water treatment plant are completed daily and that pertinent information is logged and communicated appropriately.

Under normal circumstances the water treatment plant has sufficient capacity to sustain full generation capacity without the air heater condensate pumps in service. However, the condensate pumps can help mitigate the impacts in the event of reduced capacity of the water treatment plant. Hydro schedules corrective maintenance activities based on a priority assessment. Going forward, in consideration of the water issues experienced in December 2020, Hydro will ensure that an emergency work order is executed in the event of a second, simultaneous condensate pump seal failure on the same unit. Hydro will provide an update on the status of the recommended corrective actions pertaining to this event in the November 2021 update of this report.

Power Centre C Failure

On February 21, 2021, Holyrood Unit 1 tripped. The apparent cause of the loss of the unit was due to Power Centre C, a 600 V load centre, going offline. Two of the three air compressors in the plant are fed through Power Centre C.

One air compressor is not sufficient to sustain full load operation of the power plant. Without two air compressors, and with no access to the equipment fed by Power Centre C, Unit 1 tripped. Unit 2 remained stable, but could not increase its generation output due to a loss of equipment fed through Power Centre C. While Unit 3 is not dependent on equipment fed through Power Centre C, the overhead door closest to its Forced Draft Fans VFDs was open to increase ventilation in the power house, making the temperature drop below the operational level of the VFD. This caused the loss of Unit 3’s East VFD, and the inability to increase the generation output of Unit 3. At this same time, the plant’s Pandemic Response Plan was in effect at its highest level, meaning there was only one worker from each trade available at the time of the event.

A TapRooT investigation has been initiated to determine the root cause of the failure, accompanied by a deeper, detailed technical analysis which will be carried out during the 2021 maintenance season. The sizing of the fuses protecting the 125 Vdc breaker trip circuits will be reviewed to ensure they are correctly sized, and the loads connected to each power centre will be reviewed.

Hydro will provide more information on the results of this investigation in the November 2021 update to this report.

Boiler Feed Pump Motors

On October 25, 2020, just prior to the submission of the November Report, Hydro experienced a failure of the Unit 1 Boiler Feed Pump West. Inspection and analysis at the time revealed that the pump impeller and the motor had been significantly damaged during the failure event. Hydro fully restored the pump to service on November 16, 2020 utilizing the spare pump impeller cartridge and the spare 3000 hp motor. The equipment has remained in service since that time. Hydro has also completed refurbishment of the failed components, which have been returned to local storage, available to serve as spares to mitigate any future failure. Unit 1 was offline on forced outage until November 7, 2021, then remained derated to 50% load until November 16, 2020, when the pump was returned to service.

Hydro completed a TapRooT investigation of the failure to determine causes of failure and identify corrective actions to prevent future failures. This report was completed on January 15, 2021. It has been determined that the pump failure was caused when the suction valve was closed on the operating pump in error due to miscommunication. 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.

All corrective actions recommended in the investigation report have been complete or are on schedule to be completed and implemented during the annual maintenance season. Hydro will provide the updated status of these actions in the November 2021 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.[7] 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 an annual tube inspection program, which will continue during the 2021 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 such, should a tube failure occur, the expected return to service time is accounted for in the projected DAFOR targets.

[7] Holyrood TGS experienced two tube leaks since the November 2020 filing of this report. On December 12, 2020, while flashing Unit 2 in preparation for return to service after the completion of the annual maintenance outage, a leak was discovered in a superheater tube at an attachment weld. The failed tube section was replaced by the boiler contractor and the failed section was sent to a metallurgical lab for failure analysis. Results indicated that the failure was due to a combination of stress corrosion cracking and thermal fatigue. Hydro will complete a focused inspection in this area during the 2021 outage season to look for additional similar pending failures. Hydro will also review water washing of this area and consider if a process change could reduce the corrosion that apparently contributed to the failure.
On January 18, 2021, while maintaining Unit 3 on hot standby, a tube leak was discovered at the south west windbox to waterwall tube attachment area. The failed tube was replaced by plant forces. The failure occurred in a known trouble spot on this unit, which is caused by stresses induced where the windbox attaches to the tubes. A redesign of this attachment was completed by the OEM in 2020 and is being installed during the 2021 annual outage.

Variable Frequency Drives

Forced draft fans provide combustion air required for boiler operation at the Holyrood TGS. The 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.

Hydro has entered into a service agreement with Siemens, and preventive maintenance work was completed by Siemens in 2018, 2019, and 2020 to address issues that have been encountered through VFD operation. Operating strategies have also been implemented to reduce the likelihood of VFD failures, such as pre-energizing VFD equipment prior to unit start-ups and erecting heated enclosures around the drive cabinets during the maintenance season to reduce contamination from moisture and dust. Despite these efforts there have been six incidents related to the forced draft fan VFDs during the 2020–2021 operating season that have led to deratings, trips, or forced outages.

Hydro is taking further action to reduce VFD failures. A detailed analysis of the VFD's fault logs was conducted by the plant's engineering team with support from Siemens, the OEM, and Schweitzer Engineering Laboratories, an industry expert in power systems, and manufacturer of some of the Holyrood TGS equipment. It was identified that power quality issues are likely to be responsible for VFD trips that involve replacement of power cells. Trips with failed cells are more likely to result in longer disruptions and either the derating or loss of a unit. Currently, the following strategies are being pursued to reduce reliability impacts caused by VFD issues:

1) Installation of power quality monitors to detect voltage issues that could impact the VFD's power electronics components;
2) Change to the operational philosophy of the VFDs that will keep the control and cell sections energized while the medium voltage supply to the fan is de-energized. Currently, when the forced draft fan is de-energized during outages, the whole VFD is also de-energized;
3) Keeping the overhead doors on the vicinity of Unit 3's VFDs closed during winter months. When those doors are open on cold days, the ambient temperature around the VFDs drop below the operational limits of the equipment. If required to be used, those doors shall be closed as soon as possible.
4) Investigation of the variable inlet vanes position of Unit 3. If not fully open, those vanes impose increased resistance to the flow of air from the fans into the boiler. Note that the vanes are locked in fully open position in Units 1 and 2; however, with respect to Unit 3, there has been a

history of excessive duct vibration when the vanes are fully open. The possibility of fully opening the vanes on Unit 3 is being considered.

3.1.3 Gas Turbines

At this time there remains no additional issues of concern.

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 forced outage rates ("FOR") provide a measure of the expected level of availability due to unforeseen circumstances.[8] Assumptions on FORs of generating units are updated annually in accordance with Hydro's FOR methodology, with the assumptions used in this analysis consistent with those used in Hydro's November Report.[9,10]

The FORs used in Hydro's reliability analysis vary 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. 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-

[8] 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.
[9] Hydro's current FOR methodology was provided in "Reliability and Resource Adequacy Study," Newfoundland and Labrador Hydro, rev. 1, September 6, 2019 (originally filed November 16, 2018), vol. I, att. 5.
[10] 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 extended the capacity-weight average DAFOR from 3 to 5 years, increasing the FOR to more appropriately represent the risk of failure in the near term. For the Holyrood Gas Turbine, Hydro used a scenario-based approach to estimate the FOR.

term supply adequacy. These projections of asset reliability include appropriate consideration of asset availability and deration.

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 = 18%, 20%
Holyrood GT[11]	DAUFOP = 4.9%
Happy-Valley GT[12]	DAUFOP = 12%
Stephenville GT[13]	DAUFOP = 30%
Hardwoods GT[14]	DAUFOP = 30%
Diesels	DAUFOP = 8%

With respect to the LIL, once modelled as in service, the forced outage rate 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.[15] For the purpose of this analysis, the LIL is assumed to be available at its full capacity on the in-service date, supported by the full availability of the Muskrat Falls generating units. It is assumed that delivery of the Nova Scotia Block[16] will also commence on that same in-service date.

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

[11] Holyrood Gas Turbine (“Holyrood GT”).
[12] Happy-Valley Gas Turbine (“Happy-Valley GT”).
[13] Stephenville Gas Turbine (“Stephenville GT”).
[14] Hardwoods Gas Turbine (“Hardwoods GT”).
[15] In year one of operation, the monopole forced outage rate is assumed to be 10% for each pole. The forced outage rate assumption decreases to 2.5% in year two, 1% in year three, and finally to the long-term forced outage rate of 0.556% per pole from year four onwards.
[16] The Nova Scotia Block is a firm annual commitment of 980 GWh, to be supplied from the Muskrat Falls GS on peak.

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

Asset	Reliability Metric
Hydraulic Units	DAFOR = 5.7%
Gas Turbines	DAUFOP = 8%
Corner Brook Cogen	DAUFOP = 17.48%

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 before the LIL is placed in service, 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 490 MW. 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 September 28, 2020, Hydro advised the Board of an extension to the operations of the Holyrood TGS as a generating facility to March 31, 2023.[17] 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 (2021–2025), the Holyrood TGS is assumed to be available for the entirety of the study period.

[17] Hydro previously communicated an extension to March 31, 2022 in correspondence “Extension of Holyrood Thermal Generation Station as a Generating Facility,” Newfoundland and Labrador Hydro, February 14, 2020.

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. These units were planned to be retired in 2021.

As identified in the most recent transmission planning assessment,[18] following the retirement of the Stephenville GT, 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. 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 TL 209. This project was included in Hydro's 2021 Capital Budget Application.[19] As this project will take two years to complete, it is expected that the Stephenville GT will be retired following completion of this project in 2023.[20]

With respect to the Hardwoods GT, operating hours and generation at this facility has decreased materially in recent years from levels observed in 2014 through 2018 and asset availability at these facilities is much improved over levels previously observed.[21] Given continued uncertainty regarding the reliable in-service of the LIL, Hydro plans to retain the Hardwoods GT in service until the LIL is proven reliable. Hydro 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.

As such, for the purposes of this report it is assumed that the Stephenville GT and Hardwoods GT will be retired on the same schedule as the Holyrood TGS. This is modelled as March 31, 2023, reflective of the

[18] The 2020 Final Annual Planning Assessment was posted to the NLSO OASIS site on May 7, 2020.
[19] "2021 Capital Budget Application," Newfoundland and Labrador Hydro, rev. 2, November 2, 2020 (originally filed August 4, 2020.
[20] A fully established LIL is also a pre-requisite for the retirement of the Stephenville GT.
[21] This reduction in the requirement to operate is primarily attributed to the high degree of reliability observed at 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.

full power in-service of the Muskrat Falls asset in 2021. In scenarios where it is assumed that the LIL will not be available through the study period (2021–2025), 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[22] and industrial load.[23] 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 from its industrial customers, Newfoundland Power, and Hydro's own rural service territories.

4.2 Economic Setting[24]

Newfoundland and Labrador's economic growth was greatly affected by the global economic impacts of the COVID-19 pandemic in 2020.

In 2020, the provincial government forecasted declines for many economic measures including employment, real exports, capital investment, and real gross domestic product ("GDP") with COVID-19-related work shutdowns and work suspensions cited as a contributing factor. The forecasted decrease in real exports was largely a result of forecasted declines in refined petroleum and fish exports. The future for refined petroleum exports remains at risk unless oil refining operations resume at Come By Chance or a new owner is found. Travel restrictions associated with COVID-19 resulted in lower tourism activity for 2020 and are likely to continue to impact tourism activity through 2021.

[22] Residential and general service loads of Newfoundland Power and Hydro.
[23] Larger direct customers of Hydro such as Corner Brook Pulp and Paper Limited ("CBPP"), NARL, Vale Newfoundland and Labrador Limited ("Vale"), Praxair Canada Inc., Iron Ore Company of Canada ("IOC"), and Tacora Resources Inc. ("Tacora")
[24] The economy and forecast load requirements reflected in this report do not include impacts associated with an extended period of a global COVID-19 pandemic. With respect to the pandemic, Hydro has modelled a change to 2021 energy requirements only, associated with the known impacts of COVID-19 (e.g., reduced requirements at NARL). Economic commentary reflects "The Budget 2020, Government of Newfoundland & Labrador".

On a more positive note, consumer price inflation remains low and total household income in 2021 is expected to rise. Despite subdued activity within the provincial offshore oil sector, recently announced oil discoveries and longer term exploration plans and programs bode well for a potential return to growth in this industry. Forecast provincial housing starts for 2021 are comparable to 2020 forecasts, indicating that the steep declines recently experienced are beginning to stabilize. In Labrador, construction of the underground mine at Voisey's Bay resumed following a work suspension in the spring of 2020 in response to the COVID-19 pandemic.

Looking forward through the medium term (i.e., one to five years), there are several developments that are expected to positively influence provincial economic activity, both in Labrador and on the Island. These developments include Greig NL's Placentia Bay aquaculture project, which was released from environmental assessment in 2018 and aims to bring first fish to market in 2022–2023. While some work has been completed on this project, the COVID-19 pandemic did impact salmon markets, resulting in the company slowing the pace of investments. While this may impact near-term growth, increased interest in aquaculture is expected to expand the overall value of fishing and aquaculture industry.

The mining sector also announced encouraging developments in recent years, including Vale announcing 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.

On more broad based economic terms over the medium term, adjusted real GDP is forecast to decline, being partially offset with increases in exports, driven by energy and mining projects. Capital investment is expected to be stable but lower than recent years. According to current provincial economic reports by many Canadian financial institutions, it is anticipated that Newfoundland and Labrador's economy will improve more slowly than other provinces in 2021 and growth will continue to be restrained over the medium term.

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 suggest stable or possible decline in energy requirements in the near term followed by a return to increasing energy requirements once economic conditions improve in the longer term.

4.3 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 once inputs are received from Newfoundland Power. The revised load forecast is anticipated to be the basis of Hydro's November 2021 report on near-term reliability, which will be prepared in advance of the 2021–2022 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.

Labrador Interconnected System forecast requirements increase in 2023 associated with increased IOC demand requirements following the in-service of synchronous condenser 3.[25]

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

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

			P50		
	2021	**2022**	**2023**	**2024**	**2025**
Utility	1,476	1,476	1,477	1,481	1,484
Industrial Customer	180	180	180	180	180
Island Interconnected System Customer Coincident Demand	**1,656**	**1,656**	**1,657**	**1,661**	**1,664**
Island Interconnected System Transmission Losses and Station Service	71	103	101	101	101
Total Island Interconnected System Demand	**1,727**	**1,759**	**1,758**	**1,762**	**1,765**

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

			P50		
	2021	**2022**	**2023**	**2024**	**2025**
Utility	141	143	143	144	144
Industrial Customer	279	278	301	301	301
Labrador Interconnected System Customer Coincident Demand	**420**	**421**	**444**	**445**	**446**
Labrador Interconnected System Transmission Losses and Station Service	24	24	26	26	26
Total Labrador Interconnected System Demand[26]	**444**	**445**	**470**	**471**	**472**

[25] There is potential for advancement of agreements which would result in an earlier increase in firm supply capacity to Labrador West. Should such agreements be in place for the 2021–2022 winter operating season, Hydro will revise its forecast to include the indicated firm power required following receipt of customer request. This would then be included in the base forecast used to support the November 2021 Near-Term Reliability Report.
[26] 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).

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

			P50		
	2021	**2022**	**2023**	**2024**	**2025**
Newfoundland and Labrador Interconnected System Customer Coincident Demand	2,043	2,044	2,067	2,072	2,076
Newfoundland and Labrador Interconnected System Transmission Losses and Station Service	93	125	125	125	125
Total Newfoundland and Labrador Interconnected System Demand	**2,136**	**2,169**	**2,192**	**2,197**	**2,201**

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 2021. 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.

System energy in storage remained above the minimum storage target throughout the 2020–2021 winter operating season. At the end of April 30, 2021, the total system energy in storage was 2,006 GWh, 1,786 GWh above the minimum storage limit of 220 GWh for April 2021. Figure 1 plots the 2021 and 2020 storage levels, maximum operating level storage, and the 20-year average aggregate storage for comparison.

The most recent snow survey was completed during mid-April 2021. At the time of the snow survey, runoff due to snow melt had ended at the Bay d'Espoir system and the Hinds Lake watershed, significantly earlier than previous years on record. The survey indicated that, for the system as a whole, snow water equivalent (mm) was approximately 16% of average and equivalent energy (GWh) was approximately 22% of average. Spring freshet continues at the Cat Arm reservoir and is expected to continue through May 2021.

Hydro has established minimum storage limits for the remainder of 2021 to April 30, 2022 in consideration of the unlikely event that the LIL is unable to deliver energy to the Island Interconnected System for three months during Winter 2022.[27] This will help ensure sufficient storage to reliably serve customers should the LIL become unavailable during the months that have historically high customer loads and low inflows into the reservoirs. With healthy reservoir storage across all reservoirs, successful completion of Interim Bipole Trial Operations, the continued availability of thermal energy, and access to external markets to provide the balance of load, the availability of energy in reservoir systems does not currently pose a risk to near-term resource adequacy.

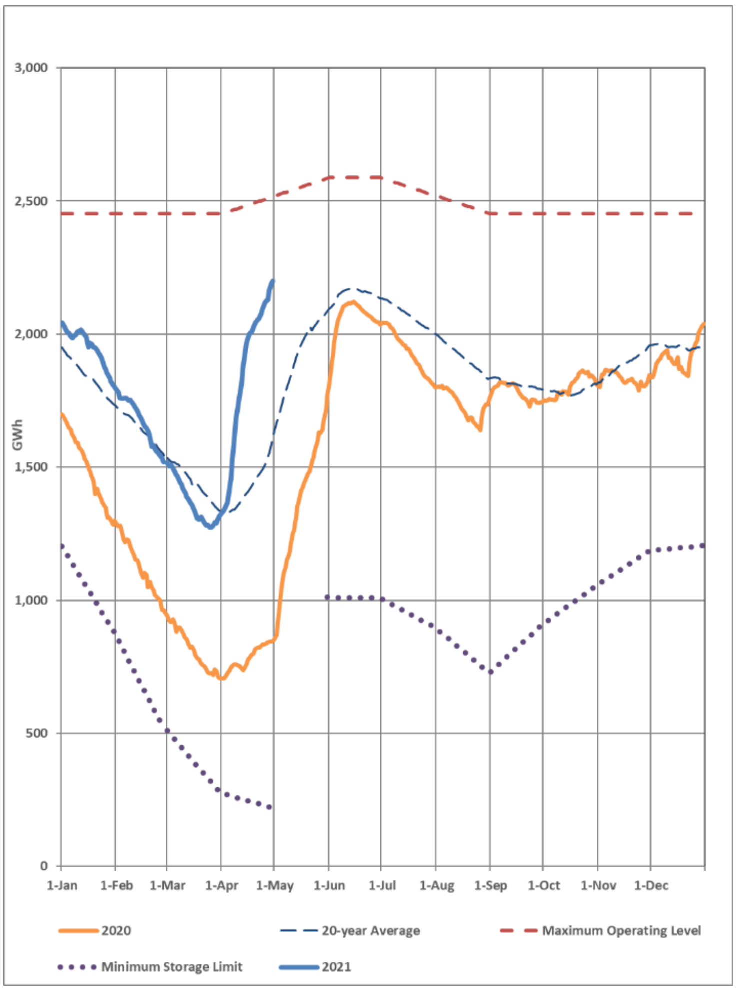

Figure 1: Total System Energy Storage for April 30. 2021

[27] The three winter months are January to March 2022, inclusive.

6.0 Results

The following subsections provide a description of the 12 scenarios considered and the anticipated system reliability in each scenario (i.e., LOLH, EUE, and NEUE results).

6.1 Scenario Analysis

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

- **Scenario 1:** Assumes that the LIL will be available at full capacity in November 2021. 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, 2023. No LIL deliveries are contemplated in advance of November 2021.
- **Scenario 2**: Varies from Scenario 1 by increasing the Holyrood TGS DAFOR to 20%.
- **Scenario 3:** Assumes that the LIL will be available at up to 225 MW for November 2021 through June 2022 and available at full capacity thereafter. 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, 2023. No LIL deliveries are contemplated in advance of November 2021.
- **Scenario 4:** Varies from Scenario 3 by increasing the Holyrood TGS DAFOR to 18%.
- **Scenario 5:** Varies from Scenario 3 by increasing the Holyrood TGS DAFOR to 20%.
- **Scenario 6:** Varies from Scenario 1 by assuming that the LIL is not available through the study period (2021 through the end of 2025). The operation of Holyrood TGS, Hardwoods GT, and Stephenville GT is extended through the study period at baseline FORs.
- **Scenario 7:** Varies from Scenario 6 by increasing the Holyrood TGS DAFOR to 18%.
- **Scenario 8:** Varies from Scenario 6 by increasing the Holyrood TGS DAFOR to 20%.
- **Scenario 9:** Varies from Scenario 8 by including 50 MW of imports during the winter season.
- **Scenario 10:** Varies from Scenario 8 by including 100 MW of imports during the winter season.
- **Scenario 11:** Varies from Scenario 6 by excluding industrial load from NARL.
- **Scenario 12:** Varies from Scenario 8 by excluding industrial load from NARL.

For scenarios 6–12 it is assumed that the contract for capacity assistance with Vale is renewed for each winter season in the study period.

For Corner Brook Pulp and Paper ("CBPP") Capacity Assistance the existing contract runs until Spring 2023. In Scenarios 1–5, this remains unchanged. In Scenarios 6–12, 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, Hardwoods GT, and 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[28]

LOLH (hours)	2021[29]	2022	2023	2024	2025
S1: Full LIL 2021, Holyrood TGS DAFOR = 15%	0.01	0.01	0.11	0.38	0.37
S2: Full LIL 2021, Holyrood TGS DAFOR = 20%	0.02	0.01	0.11	N/A	N/A
S3: LIL at 225 MW to June 2022, Holyrood TGS DAFOR = 15%	0.01	0.03	N/A	N/A	N/A
S4: LIL at 225 MW to June 2022, Holyrood TGS DAFOR = 18%	0.03	0.06	N/A	N/A	N/A
S5: LIL at 225 MW to June 2022, Holyrood TGS DAFOR = 20%	0.03	0.08	N/A	N/A	N/A
S6: No LIL, Holyrood TGS DAFOR = 15%	0.44	3.15	3.23	3.65	3.84
S7: No LIL, Holyrood TGS DAFOR = 18%	0.71	4.77	4.77	5.44	5.73
S8: No LIL, Holyrood TGS DAFOR = 20%	0.88	6.10	6.12	6.93	7.26
S9: No LIL, Holyrood TGS DAFOR = 20%, 50 MW imports	0.48	3.20	3.13	3.39	3.82
S10: No LIL, Holyrood TGS DAFOR = 20%, 100 MW imports	0.27	1.66	1.59	1.86	1.95
S11: No LIL, Holyrood TGS DAFOR = 15%, NARL-adjusted forecast	N/A	2.08	N/A	N/A	N/A
S12: No LIL, Holyrood TGS DAFOR = 20%, NARL-adjusted forecast	N/A	4.03	N/A	N/A	N/A

[28] Note that the prepared load forecast for 2021 included demand and energy requirements for NARL. As a sensitivity, NARLs contribution to system demand and energy requirements was removed from the forecast in 2022. As such there are no reportable results for 2021 for this scenario.
[29] Results for 2021 are for the remainder of the year (June 1 through December 31).

EUE (MWh)	2021[30]	2022	2023	2024	2025
S1: Full LIL 2021, Holyrood TGS DAFOR = 15%	0	0	10	36	36
S2: Full LIL 2021, Holyrood TGS DAFOR = 20%	1	1	10	N/A	N/A
S3: LIL at 225 MW to June 2022, Holyrood TGS DAFOR = 15%	1	0	N/A	N/A	N/A
S4: LIL at 225 MW to June 2022, Holyrood TGS DAFOR = 18%	1	3	N/A	N/A	N/A
S5: LIL at 225 MW to June 2022, Holyrood TGS DAFOR = 20%	1	4	N/A	N/A	N/A
S6: No LIL, Holyrood TGS DAFOR = 15%	25	171	172	198	209
S7: No LIL, Holyrood TGS DAFOR = 18%	41	266	265	305	321
S8: No LIL, Holyrood TGS DAFOR = 20%	50	344	342	398	414
S9: No LIL, Holyrood TGS DAFOR = 20%, 50 MW imports	26	168	166	194	201
S10: No LIL, Holyrood TGS DAFOR = 20%, 100 MW imports	13	80	80	93	97
S11: No LIL, Holyrood TGS DAFOR = 15%, NARL-adjusted forecast	N/A	109	N/A	N/A	N/A
S12: No LIL, Holyrood TGS DAFOR = 20%, NARL-adjusted forecast	N/A	219	N/A	N/A	N/A

NEUE (ppm)[31]	2021[32]	2022	2023	2024	2025
S1: Full LIL 2021, Holyrood TGS DAFOR = 15%	9.86	0.05	1.27	4.43	4.36
S2: Full LIL 2021, Holyrood TGS DAFOR = 20%	20.39	0.1	1.16	N/A	N/A
S3: LIL at 225 MW to June 2022, Holyrood TGS DAFOR = 15%	9.71	0.13	N/A	N/A	N/A
S4: LIL at 225 MW to June 2022, Holyrood TGS DAFOR = 18%	15.69	0.31	N/A	N/A	N/A
S5: LIL at 225 MW to June 2022, Holyrood TGS DAFOR = 20%	20.59	0.4	N/A	N/A	N/A
S6: No LIL, Holyrood TGS DAFOR = 15%	12.66	19.83	19.87	22.93	24.02
S7: No LIL, Holyrood TGS DAFOR = 18%	20.27	30.83	30.58	35.21	36.87
S8: No LIL, Holyrood TGS DAFOR = 20%	26.3	39.8	39.62	45.89	47.35
S9: No LIL, Holyrood TGS DAFOR = 20%, 50 MW imports	12.2	19.47	19.15	22.3	23.05
S10: No LIL, Holyrood TGS DAFOR = 20%, 100 MW imports	5.68	9.21	9.21	10.61	10.96
S11: No LIL, Holyrood TGS DAFOR = 15%, NARL-adjusted forecast	N/A	12.95	N/A	N/A	N/A
S12: No LIL, Holyrood TGS DAFOR = 20%, NARL-adjusted forecast	N/A	26.25	N/A	N/A	N/A

The results of scenarios 1 through 5 indicate that the availability of the LIL, at partial or full capability, backed up by the Holyrood TGS mitigates the risk of lost load and unserved energy in the near-term. Once Holyrood TGS is retired, higher levels of LOLH and EUE are observed, though both remain at acceptable levels through the study period.

[30] Results for 2021 are for the remainder of the year (June 1 through December 31).
[31] NEUE given here in parts per million and it 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.
[32] Results for 2021 are for the remainder of the year (June 1 through December 31).

The results of Scenarios 6 through 9 indicate that if the LIL is unavailable during the winter operating season, both LOLH and EUE grow as the unavailability of Holyrood TGS increases.

As such, 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.[33] 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 100 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.

In the event that NARL does not resume production in 2022, improved system reliability is observed relative to Scenarios 6 and 8, with overall reliability would be highly dependent on the availability of Holyrood.

6.2.2 Monthly Assessment Results

Finally, if NARL is not operating in 2022, there are improvements in overall system reliability, dependant on the reliability of the Holyrood TGS.

Table 7 through 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 though 5, the availability of the LIL, at partial or full capability, backed up by the Holyrood TGS in 2022 and 2023 mitigates the risk of lost load and unserved energy. Once Holyrood TGS and the Hardwoods GT and Stephenville GT are retired, both LOLH and EUE increase but remain at acceptable levels through the study period.

[33] For reference, the weighted average thermal DAFOR for 12 months ending September 2020 was 2.08% as reported in the "Quarterly Report on Performance of Generating Units for the Quarter Ended September 30, 2020," Newfoundland and Labrador Hydro, October 30, 2020.

In Scenarios 6 through 8, the LOLH and EUE remain high throughout the study period, and without mitigation, indicate a relatively high probability of lost load on the system until the LIL is found fully reliable.

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 firm imports could 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.

Finally, if NARL is not operating in 2022, there are improvements in overall system reliability, dependant on the reliability of the Holyrood TGS.

Table 7: Monthly LOLH and EUE for 2021[34]

LOLH (hours)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
S1: Full LIL 2021, Holyrood TGS DAFOR = 15%	N/A	N/A	N/A	N/A	N/A	0	0	0	0	0	0	0.01
S2: Full LIL 2021, Holyrood TGS DAFOR = 20%	N/A	N/A	N/A	N/A	N/A	0	0	0	0	0	0	0.02
S3: LIL at 225 MW to June 2022, Holyrood TGS DAFOR = 15%	N/A	N/A	N/A	N/A	N/A	0	0	0	0	0	0	0.01
S4: LIL at 225 MW to June 2022, Holyrood TGS DAFOR = 18%	N/A	N/A	N/A	N/A	N/A	0	0	0	0	0	0	0.03
S5: LIL at 225 MW to June 2022, Holyrood TGS DAFOR = 20%	N/A	N/A	N/A	N/A	N/A	0	0	0	0	0	0	0.03
S6: No LIL, Holyrood TGS DAFOR = 15%	N/A	N/A	N/A	N/A	N/A	0	0	0	0	0	0.02	0.42
S7: No LIL, Holyrood TGS DAFOR = 18%	N/A	N/A	N/A	N/A	N/A	0	0	0	0	0	0.04	0.67
S8: No LIL, Holyrood TGS DAFOR = 20%	N/A	N/A	N/A	N/A	N/A	0	0	0	0	0	0.05	0.83
S9: No LIL, Holyrood TGS DAFOR = 20%, 50 MW imports	N/A	N/A	N/A	N/A	N/A	0	0	0	0	0	0.05	0.43
S10: No LIL, Holyrood TGS DAFOR = 20%, 100 MW imports	N/A	N/A	N/A	N/A	N/A	0	0	0	0	0	0.04	0.23
S11: No LIL, Holyrood TGS DAFOR = 15%, NARL-adjusted forecast	N/A	N/A	N/A	N/A	N/A	0	0	0	0	0	0.02	0.46
S12: No LIL, Holyrood TGS DAFOR = 20%, NARL-adjusted forecast	N/A	N/A	N/A	N/A	N/A	0	0	0	0	0	0.04	0.80
EUE (MWh)	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**
S1: Full LIL 2021, Holyrood TGS DAFOR = 15%	N/A	N/A	N/A	N/A	N/A	0	0	0	0	0	0	0
S2: Full LIL 2021, Holyrood TGS DAFOR = 20%	N/A	N/A	N/A	N/A	N/A	0	0	0	0	0	0	1
S3: LIL at 225 MW to June 2022, Holyrood TGS DAFOR = 15%	N/A	N/A	N/A	N/A	N/A	0	0	0	0	0	0	1
S4: LIL at 225 MW to June 2022, Holyrood TGS DAFOR = 18%	N/A	N/A	N/A	N/A	N/A	0	0	0	0	0	0	1
S5: LIL at 225 MW to June 2022, Holyrood TGS DAFOR = 20%	N/A	N/A	N/A	N/A	N/A	0	0	0	0	0	0	1
S6: No LIL, Holyrood TGS DAFOR = 15%	N/A	N/A	N/A	N/A	N/A	0	0	0	0	0	1	24
S7: No LIL, Holyrood TGS DAFOR = 18%	N/A	N/A	N/A	N/A	N/A	0	0	0	0	0	2	39
S8: No LIL, Holyrood TGS DAFOR = 20%	N/A	N/A	N/A	N/A	N/A	0	0	0	0	0	2	48
S9: No LIL, Holyrood TGS DAFOR = 20%, 50 MW imports	N/A	N/A	N/A	N/A	N/A	0	0	0	0	0	2	24
S10: No LIL, Holyrood TGS DAFOR = 20%, 100 MW imports	N/A	N/A	N/A	N/A	N/A	0	0	0	0	0	2	11
S11: No LIL, Holyrood TGS DAFOR = 15%, NARL-adjusted forecast	N/A	N/A	N/A	N/A	N/A	0	0	0	0	0	1	26
S12: No LIL, Holyrood TGS DAFOR = 20%, NARL-adjusted forecast	N/A	N/A	N/A	N/A	N/A	0	0	0	0	0	2	47

[34] Monthly results may not add up to annual results—this is due to rounding.

Table 8: Monthly LOLH and EUE for 2022

LOLH (hours)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
S1: Full LIL 2021, Holyrood TGS DAFOR = 15%	0	0	0	0	0	0	0	0	0	0	0	0.01
S2: Full LIL 2021, Holyrood TGS DAFOR = 20%	0	0	0	0	0	0	0	0	0	0	0	0.01
S3: LIL at 225 MW to June 2022, Holyrood TGS DAFOR = 15%	0.01	0.01	0.01	0	0	0	0	0	0	0	0	0
S4: LIL at 225 MW to June 2022, Holyrood TGS DAFOR = 18%	0.03	0.02	0.01	0	0	0	0	0	0	0	0	0
S5: LIL at 225 MW to June 2022, Holyrood TGS DAFOR = 20%	0.03	0.02	0.02	0	0	0	0	0	0	0	0	0.01
S6: No LIL, Holyrood TGS DAFOR = 15%	1.17	0.76	0.52	0	0	0	0	0	0	0	0.03	0.67
S7: No LIL, Holyrood TGS DAFOR = 18%	1.78	1.16	0.78	0.01	0	0	0	0	0	0	0.06	0.98
S8: No LIL, Holyrood TGS DAFOR = 20%	2.31	1.48	1.00	0.01	0	0	0	0	0	0	0.07	1.23
S9: No LIL, Holyrood TGS DAFOR = 20%, 50 MW imports	1.20	0.74	0.52	0.01	0	0	0	0	0	0	0.07	0.66
S10: No LIL, Holyrood TGS DAFOR = 20%, 100 MW imports	0.59	0.39	0.26	0.01	0	0	0	0	0	0	0.07	0.34
S11: No LIL, Holyrood TGS DAFOR = 15%, NARL-adjusted forecast	0.78	0.49	0.33	0	0	0	0	0	0	0	0.02	0.46
S12: No LIL, Holyrood TGS DAFOR = 20%, NARL-adjusted forecast	1.54	0.97	0.68	0	0	0	0	0	0	0	0.04	0.80
EUE (MWh)	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**
S1: Full LIL 2021, Holyrood TGS DAFOR = 15%	0	0	0	0	0	0	0	0	0	0	0	0
S2: Full LIL 2021, Holyrood TGS DAFOR = 20%	0	0	0	0	0	0	0	0	0	0	0	1
S3: LIL at 225 MW to June 2022, Holyrood TGS DAFOR = 15%	0	0	0	0	0	0	0	0	0	0	0	0
S4: LIL at 225 MW to June 2022, Holyrood TGS DAFOR = 18%	1	1	1	0	0	0	0	0	0	0	0	0
S5: LIL at 225 MW to June 2022, Holyrood TGS DAFOR = 20%	1	1	1	0	0	0	0	0	0	0	0	1
S6: No LIL, Holyrood TGS DAFOR = 15%	64	39	28	0	0	0	0	0	0	0	2	38
S7: No LIL, Holyrood TGS DAFOR = 18%	98	63	44	0	0	0	0	0	0	0	3	58
S8: No LIL, Holyrood TGS DAFOR = 20%	131	80	55	0	0	0	0	0	0	0	4	74
S9: No LIL, Holyrood TGS DAFOR = 20%, 50 MW imports	62	36	27	0	0	0	0	0	0	0	4	39
S10: No LIL, Holyrood TGS DAFOR = 20%, 100 MW imports	28	18	12	0	0	0	0	0	0	0	4	18
S11: No LIL, Holyrood TGS DAFOR = 15%, NARL-adjusted forecast	40	25	17	0	0	0	0	0	0	0	1	26
S12: No LIL, Holyrood TGS DAFOR = 20%, NARL-adjusted forecast	83	50	37	0	0	0	0	0	0	0	2	47

Table 9: Monthly LOLH and EUE for 2023

LOLH (hours)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
S1: Full LIL 2021, Holyrood TGS DAFOR = 15%	0	0	0	0.01	0	0	0	0	0	0	0.01	0.09
S2: Full LIL 2021, Holyrood TGS DAFOR = 20%	0	0	0	0.01	0	0	0	0	0	0	0.01	0.09
S3: LIL at 225 MW to June 2022, 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
S4: LIL at 225 MW to June 2022, 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
S5: LIL at 225 MW to June 2022, 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
S6: No LIL, Holyrood TGS DAFOR = 15%	1.13	0.82	0.5	0	0	0	0.01	0	0	0	0.04	0.73
S7: No LIL, Holyrood TGS DAFOR = 18%	1.7	1.21	0.73	0.01	0	0	0.01	0	0	0	0.06	1.05
S8: No LIL, Holyrood TGS DAFOR = 20%	2.19	1.55	0.95	0.01	0	0	0.01	0	0	0	0.08	1.33
S9: No LIL, Holyrood TGS DAFOR = 20%, 50 MW imports	1.13	0.81	0.49	0.01	0	0	0.01	0	0	0	0.08	0.68
S10: No LIL, Holyrood TGS DAFOR = 20%, 100 MW imports	0.55	0.4	0.25	0.01	0	0	0.01	0	0	0	0.08	0.37
S11: No LIL, Holyrood TGS DAFOR = 15%, NARL-adjusted forecast	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
S12: No LIL, Holyrood TGS DAFOR = 20%, NARL-adjusted forecast	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: Full LIL 2021, Holyrood TGS DAFOR = 15%	0	0	0	0	0	0	0	0	0	0	1	9
S2: Full LIL 2021, Holyrood TGS DAFOR = 20%	0	0	0	0	0	0	0	0	0	0	1	9
S3: LIL at 225 MW to June 2022, 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
S4: LIL at 225 MW to June 2022, 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
S5: LIL at 225 MW to June 2022, 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
S6: No LIL, Holyrood TGS DAFOR = 15%	60	42	26	0	0	0	0	0	0	0	2	42
S7: No LIL, Holyrood TGS DAFOR = 18%	94	64	41	0	0	0	0	0	0	0	3	63
S8: No LIL, Holyrood TGS DAFOR = 20%	120	84	54	0	0	0	0	0	0	0	4	80
S9: No LIL, Holyrood TGS DAFOR = 20%, 50 MW imports	57	41	26	0	0	0	0	0	0	0	4	38
S10: No LIL, Holyrood TGS DAFOR = 20%, 100 MW imports	27	19	11	0	0	0	0	0	0	0	4	19
S11: No LIL, Holyrood TGS DAFOR = 15%, NARL-adjusted forecast	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
S12: No LIL, Holyrood TGS DAFOR = 20%, NARL-adjusted forecast	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

Table 10: Monthly LOLH and EUE for 2024

LOLH (hours)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
S1: Full LIL 2021, Holyrood TGS DAFOR = 15%	0.13	0.11	0.06	0.01	0	0	0	0	0	0	0	0.07
S2: Full LIL 2021, 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
S3: LIL at 225 MW to June 2022, 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
S4: LIL at 225 MW to June 2022, 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
S5: LIL at 225 MW to June 2022, 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
S6: No LIL, Holyrood TGS DAFOR = 15%	1.54	0.82	0.65	0.01	0	0	0	0	0	0	0	0.63
S7: No LIL, Holyrood TGS DAFOR = 18%	2.29	1.25	0.96	0.01	0	0	0	0	0	0	0	0.93
S8: No LIL, Holyrood TGS DAFOR = 20%	2.92	1.62	1.21	0.01	0	0	0	0	0	0	0	1.17
S9: No LIL, Holyrood TGS DAFOR = 20%, 50 MW imports	1.56	0.83	0.62	0.01	0	0	0	0	0	0	0	0.37
S10: No LIL, Holyrood TGS DAFOR = 20%, 100 MW imports	0.76	0.43	0.32	0.01	0	0	0	0	0	0	0	0.34
S11: No LIL, Holyrood TGS DAFOR = 15%, NARL-adjusted forecast	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
S12: No LIL, Holyrood TGS DAFOR = 20%, NARL-adjusted forecast	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: Full LIL 2021, Holyrood TGS DAFOR = 15%	13	11	6	0	0	0	0	0	0	0	0	6
S2: Full LIL 2021, 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
S3: LIL at 225 MW to June 2022, 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
S4: LIL at 225 MW to June 2022, 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
S5: LIL at 225 MW to June 2022, 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
S6: No LIL, Holyrood TGS DAFOR = 15%	85	43	35	0	0	0	0	0	0	0	0	35
S7: No LIL, Holyrood TGS DAFOR = 18%	128	67	54	0	0	0	0	0	0	0	0	56
S8: No LIL, Holyrood TGS DAFOR = 20%	167	90	67	1	0	0	0	0	0	0	0	73
S9: No LIL, Holyrood TGS DAFOR = 20%, 50 MW imports	82	43	32	1	0	0	0	0	0	0	0	36
S10: No LIL, Holyrood TGS DAFOR = 20%, 100 MW imports	37	21	15	1	0	0	0	0	0	0	0	19
S11: No LIL, Holyrood TGS DAFOR = 15%, NARL-adjusted forecast	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
S12: No LIL, Holyrood TGS DAFOR = 20%, NARL-adjusted forecast	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

Table 11: Monthly LOLH and EUE for 2025

LOLH (hours)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
S1: Full LIL 2021, Holyrood TGS DAFOR = 15%	0.12	0.11	0.06	0	0	0	0	0	0	0	0	0.08
S2: Full LIL 2021, 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
S3: LIL at 225 MW to June 2022, 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
S4: LIL at 225 MW to June 2022, 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
S5: LIL at 225 MW to June 2022, 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
S6: No LIL, Holyrood TGS DAFOR = 15%	1.46	0.9	0.68	0.01	0	0	0.01	0	0	0	0	0.78
S7: No LIL, Holyrood TGS DAFOR = 18%	2.20	1.37	1.00	0.01	0	0	0.01	0	0	0	0	1.14
S8: No LIL, Holyrood TGS DAFOR = 20%	2.86	1.73	1.26	0.02	0	0	0.01	0	0	0	0	1.38
S9: No LIL, Holyrood TGS DAFOR = 20%, 50 MW imports	1.49	0.87	0.65	0.02	0	0	0.01	0	0	0	0	0.78
S10: No LIL, Holyrood TGS DAFOR = 20%, 100 MW imports	0.75	0.43	0.32	0.02	0	0	0.01	0	0	0	0	0.42
S11: No LIL, Holyrood TGS DAFOR = 15%, NARL-adjusted forecast	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
S12: No LIL, Holyrood TGS DAFOR = 20%, NARL-adjusted forecast	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: Full LIL 2021, Holyrood TGS DAFOR = 15%	12	11	6	0	0	0	0	0	0	0	0	7
S2: Full LIL 2021, 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
S3: LIL at 225 MW to June 2022, 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
S4: LIL at 225 MW to June 2022, 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
S5: LIL at 225 MW to June 2022, 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
S6: No LIL, Holyrood TGS DAFOR = 15%	80	48	36	0	0	0	0	0	0	0	0	45
S7: No LIL, Holyrood TGS DAFOR = 18%	125	74	56	0	0	0	0	0	0	0	0	66
S8: No LIL, Holyrood TGS DAFOR = 20%	163	95	71	1	0	0	0	0	0	0	0	84
S9: No LIL, Holyrood TGS DAFOR = 20%, 50 MW imports	77	45	34	1	0	0	0	0	0	0	0	44
S10: No LIL, Holyrood TGS DAFOR = 20%, 100 MW imports	36	21	17	1	0	0	0	0	0	0	0	22
S11: No LIL, Holyrood TGS DAFOR = 15%, NARL-adjusted forecast	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
S12: No LIL, Holyrood TGS DAFOR = 20%, NARL-adjusted forecast	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

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 Holyrood TGS as a generating facility until March 31, 2023. Hydro will inform the Board of any changes to this time frame as it continues to monitor LIL progress and schedules. Hydro also plans to extend operation of the Hardwoods GT and retire this asset at the same time as the Holyrood TGS.

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. For the upcoming winter, Hydro has established minimum storage limits which consider the possibility of three months of unavailability of the LIL. 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 work closely with Nalcor Energy'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. Hydro is also focused on successful execution of its annual maintenance program and completion of other high priority work, including the refurbishment of identified cracks in Bay d'Espoir Penstock 1 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 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 in-service of the Muskrat Falls Project Assets.