newfoundland labrador hydro

Hydro Place. 500 Columbus Drive.
P.O. Box 12400. St. John's. NL
Canada A1B 4K7
t. 709.737.1400 f. 709.737.1800
www.nlh.nl.ca

November 15, 2021

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 – November 2021

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

Shirley A. Walsh
Senior Regulatory Counsel
SAW/kd.sk

ecc: **Board of Commissioners of Public Utilities**
Jacqui H. Glynn
Maureen P. Greene, Q.C.
PUB Official Email

Newfoundland Power
Dominic J. Foley
Lindsay S.A. Hollett
Regulatory Email

Consumer Advocate
Dennis M. Browne, Q.C., Browne Fitzgerald Morgan & Avis
Stephen F. Fitzgerald, Browne Fitzgerald Morgan & Avis
Sarah G. Fitzgerald, Browne Fitzgerald Morgan & Avis
Bernice Bailey, Browne Fitzgerald Morgan & Avis
Bernard M. Coffey, Q.C.

Industrial Customer Group
Paul L. Coxworthy, Stewart McKelvey
Denis J. Fleming, Cox & Palmer
Dean A. Porter, Poole Althouse

Labrador Interconnected Group
Senwung F. Luk, Olthuis Kleer Townshend LLP
Julia K.G. Brown, Olthuis Kleer Townshend LLP

Reliability and Resource Adequacy Study 2021 Update

Volume II: Near-Term Reliability Report – November Report

November 15, 2021

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 study period, from 2022–2025. 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 each of the next four years (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 May 2021 Near-Term Reliability Report ("May Report"),[3] Units 2 and 3 at the Muskrat Falls Generating Station have been released for service, commissioning of Unit 4 is currently underway, and Unit 1 has been fully released for service. Additionally, since filing the May Report, the Labrador-Island Link ("LIL") has been successfully tested and operated at 312 MW, an increase from the prior established operational limit of 225 MW.

Hydro notes that issues have arisen during execution of the annual maintenance program on Upper Salmon,[4] Bay d'Espoir[5] Unit 5, and Holyrood TGS Units 1 and 3. In each case, outages were extended to allow for thorough investigations and corrective actions to mitigate risk going into the 2021–2022 winter operating season.

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. There is potential for some level of power transfer over the LIL 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.

[3] "Reliability and Resource Adequacy 2021 Update – Volume II: Near-Term Reliability Report – May Report," Newfoundland and Labrador Hydro, May 17, 2021.
[4] Upper Salmon Hydroelectric Generating Station ("Upper Salmon").
[5] Bay d'Espoir Hydroelectric Generating Facility ("Bay d'Espoir").

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"),[6] with updates to reflect current system assumptions.[7]

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.[8]

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;[9]
- Past historical rates; and
- Assumptions used in assessment of resource adequacy.

The most recent report was submitted on October 29, 2021, for the quarter ended September 30, 2021.[10] 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.

[6] "Reliability and Resource Adequacy Study," Newfoundland and Labrador Hydro, rev. September 6, 2019 (originally filed November 16, 2018).
[7] 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").
[8] NLSO Standard "Transmission Planning Criteria Doc # TP-S-007," Newfoundland and Labrador Hydro, August 25, 2021.
[9] Quarterly Report on Performance of Generating Units.
[10] "Quarterly Report on Performance of Generating Units for the Twelve Months Ended September 30, 2021," Newfoundland and Labrador Hydro, October 29, 2021.

3.1 Factors Affecting Recent Historical Generating Asset Reliability

Hydro has reviewed the factors affecting generating unit reliability since filing its May 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: New (Upper Salmon rotor rim guidance block defects), continued monitoring (Bay d'Espoir penstocks and Upper Salmon rotor rim key cracking), ongoing (Granite Canal[11] control system), and resolved (Bay d'Espoir Unit 1 vibration);
- Thermal Facilities: Continued monitoring (power centre C failure, boiler feed pump motor issues), ongoing (unit boiler tubes, VFD[12]), and resolved (water treatment plant – low feed water production); 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.

[11] Granite Canal Hydroelectric Generating Station ("Granite Canal").
[12] Variable frequency drives ("VFD").

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.

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 took place during the Unit 1 scheduled annual maintenance with scope consisting of the comprehensive analysis of generator air gaps, seal clearances, runner elevations, bolt torques and oil analysis; nothing of concern was found. Since filing the May Report Hydro has continued to monitor the trending data of Unit 1 and results indicate that the vibration and temperature levels are stable and not increasing.

Hydro considers this issue resolved.

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.[13] 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

[13] "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.

analysis and engineering review were filed with the Board on June 3, 2020.[14] 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.

Hydro has continued to take proactive measures to reduce downtime should another penstock leak occur. Hydro has maintained its inventory of pre-rolled steel plate, consulted with third-party contractors to confirm priority availability of local welding resources, and will mobilize excavator to the penstock area in December 2021 to avoid potential transportation issues during winter months when the access roads can be snow covered and icy. 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 2021 inspections were completed for all three penstocks. As previously reported, during the scheduled inspection of Penstock 1 in May 2021, 31 indications of weld deterioration were identified in 16 longitudinal weld seams over an approximately 200 foot span of the penstock. The indications found varied in length, ranging from a couple of inches to eight feet. The indications were similar in condition to those discovered in recent years and were shallow in depth. Weld refurbishment was completed and the penstock was returned 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 in 2022.

The inspections for Penstock 2 and 3 were completed in June and August 2021, respectively, and did not identity any major defects or areas of concern for the near term.

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[14] "2019 Failure of Bay d'Espoir Penstock 1 and Plan Regarding Penstock Life Extension," Newfoundland and Labrador Hydro, June 3, 2020.

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 1 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 the root cause of 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. Hydro plans to submit a supplemental capital budget application to undertake additional work to address the root causes in 2022. In addition to the block replacement, the OEM has recommended implementing a NDT inspection program of the blocks at 12-week intervals until the 2022 work scope is completed. Hydro now includes this inspection program in its maintenance activities.

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 2022 work scope. To offset the impact of an unplanned outage, Hydro is advancing procurement of long lead materials that would address the underlying root causes.

Granite Canal Control System

A thorough engineering assessment of the Granit 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. 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 in the process of being procured.

3.1.2 Thermal

Power Centre C Failure

On February 21, 2021, Holyrood Unit 1 tripped. The 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 supplied 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 the generation output could not be increased due to a loss of equipment supplied through power centre C. While Unit 3 is not dependent on equipment supplied through power centre C, the overhead door closest to its forced draft fans' VFDs was opened to increase ventilation in the power house, which resulted in the temperature dropping 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, Holyrood TGS' 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 was conducted to determine the root cause of the failure, accompanied by a deeper, detailed technical analysis which was carried out during the 2021 maintenance season. The investigation identified that a series of factors aligned to cause the failure. 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.

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. In addition, a fusing review will be conducted in 2022.

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

Boiler Feed Pump Motors

On October 25, 2020, 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. Unit 1 was offline on a forced outage until November 7, 2020, then remained derated to 50% load until November 16, 2020, when the pump was returned to service. Hydro fully restored the pump to service on November 16, 2020 utilizing the spare pump impeller cartridge and the spare 3,000 horsepower 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.

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.

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 May 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 continued 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.

Since the May Report, Holyrood TGS experienced a tube leak on the Unit 3 boiler. This was a cold-side rupture that occurred on September 11, 2021 during start-up. This failure occurred in the known trouble spot on this unit, which is caused by stresses induced where the windbox attaches to the tubes. As reported in the May Report, a tube leak occurred in January 2021 in a similar location. A redesign of this attachment was completed by the OEM and was installed during the 2021 annual outage as planned. This work included the proactive replacement of all tubes to which the windbox structure was welded, as designated by the OEM. The tube that failed in September 2021 was adjacent to the tubes that were proactively replaced in 2021, but not designated by the OEM as one to be replaced.

After completion of the planned work in 2021, it was thought that this specific tube failure risk had been mitigated. Because of this, and the fact that the failure was a cold side rupture, the unit could not be returned to service until the failure was thoroughly investigated, and any other existing damage within the boiler tubes identified and removed. 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 this process.

Because the damage that led to the failure initiates at the inside surface of the tubes, inspection had to be completed from the inside of the tubes using specialized probes designed to detect damage in the tube. As such, a section of each tube spanning the areas of concern was cut out to provide access for the specialized probes to pass through the tube. Any tubes found to have indications were replaced.

A total of 69 tubes were cut for testing and inspection and 8 defects were found and removed. The welding work took approximately six weeks to complete including the replacement of the cut tubes. Efforts remain underway to restore the boiler in preparation for start-up. Hydro considers this specific issue on Unit 3 to be resolved. 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 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 been dealing with significant reliability issues related to this equipment and the VFDs on the unit forced draft fans continue to be a significant risk for forced outages. In September 2021, following completion of the annual preventive maintenance program by the OEM (Siemens) service technician, 9 out of 24 VFD power cells[15] on that unit failed despite following OEM recommendations for outage periods and taking significant mitigating measures to keep the drives clean and dry.[16]

[15] Each drive utilizes four power cells per phase and a failure of two cells on the same phase will cause the drive to trip.
[16] Heated enclosures were erected around the drive cabinets during the maintenance season to reduce contamination from moisture and dust. Operating strategies have been implemented to reduce the likelihood of VFD failures, such as pre-energizing VFD equipment prior to unit start-ups.

Additionally, as a result of the COVID-19 pandemic, Siemens has advised that global shortages of microchips and other electronic components will extend turnaround time for failed power cells to between 48 and 52 weeks. As a result of this, and the nine recent failures of power cells, Hydro had concern regarding the availability of spare cells to support operation. All available cells (five) were purchased from Siemens, and a third-party company with experience in VFD cells, have been mobilized to site to refurbish as many failed cells as possible using its stockpile of components. Hydro is also moving forward with plans to bypass the drives on Unit 3 and return to the original inlet vane air flow control. This action will eliminate the risk on the bypassed unit and provide additional spare components to mitigate risk on the other units. The actions taken will help to ensure the availability of sufficient power cells to support reliable operation through the 2021–2022 winter operating season.

In the May Report, Hydro reported on further actions to reduce VFD failures. These actions are continuing to support operation of the VFDs on Units 1 and 2. A detailed analysis of the VFD's fault logs was conducted by the Holyrood TGS' 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. Power quality monitors were installed in the 2021 maintenance outage season to detect voltage issues that could impact the VFD's power electronics components. These will be monitored during the winter operating season. Also, a 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 is being considered for 2022.[17]

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 have since been implemented. Many of these were focused on

[17] Currently, when the forced draft fan is de-energized during outages, the whole VFD is also de-energized.

ensuring that sufficient checks of the water treatment plant are completed daily and that pertinent information is logged and communicated appropriately. All air heater condensate pumps are in good operating condition heading into the 2021–2022 winter operating season and maintenance practice has been revised to ensure that failure of these pumps will be given high priority to return them to service quickly.

Hydro considers this issue resolved.

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 FORs provide a measure of the expected level of availability due to unforeseen circumstances.[18] Assumptions on FORs of generating units are updated annually in accordance with Hydro's FOR methodology.[19]

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.

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[18] FOR refers to an input to the reliability model, which represents the percentage of hours in a year when a unit is unavailable.
[19] 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 May 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.

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.

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	DAUFOP = 4.9%
Happy-Valley GT[20]	DAUFOP = 12%
Stephenville GT[21]	DAUFOP = 30%
Hardwoods GT[22]	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.[23] Given the delays experienced in commissioning to date and the complexity of the commissioning process, Hydro has modified the FOR profile used for the LIL. Analysis completed in prior Near-Term Reliability Report used a profile of 10% FOR in year one of operation, decreasing to 2.5% in year two, 1.0% in year three, and 0.556% per pole, or the design criteria, in year four. In the current analysis, Hydro has retained the year one assumption of 10% FOR, and has modified the year 2 assumption to reflect a FOR of 5%, before assuming the same declining FOR profile of 2.5% in year 3, 1% in year 4 and the design criteria of 0.556% in year 5. 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 its full capacity on the in-service date, supported by the full availability of the Muskrat Falls generating units. Delivery of the Nova Scotia

[20] Happy-Valley Gas Turbine ("Happy-Valley GT").
[21] Stephenville Gas Turbine ("Stephenville GT").
[22] Hardwoods Gas Turbine ("Hardwoods GT").
[23] In year one of operation, the monopole FOR is assumed to be 10% for each pole. The FOR assumption decreases to 5.0% in year two, 2.5% in year three, and 1.0% per pole in year four. It is assumed that the LIL would reach its design criteria FOR of 0.556% per pole in year five.

Block commenced in August 2021, with the first physical delivery taking place on August 17, 2021.[24] 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. In instances where the LIL is partially available, the Nova Scotia Block is delivered on a *pro-rata* basis.

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 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

[24] 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.

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,[25] Hydro advised the Board of an extension to the operations of the Holyrood TGS as a generating facility to March 31, 2023. 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,[26] 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."[27] 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.[28]

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.[29]

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[25] "The Liberty Consulting Group Eighth Quarterly Monitoring Report on the Integration of Power Supply Facilities to the Island Interconnected System – Monthly Update," Newfoundland and Labrador Hydro, September 28, 2020.
[26] The 2020 Final Annual Planning Assessment was posted to the NLSO OASIS site on May 7, 2020.
[27] "2021 Capital Budget Application," Newfoundland and Labrador Hydro, rev. 2, November 2, 2020 (originally filed August 4, 2020).
[28] A fully established LIL is also a prerequisite for the retirement of the Stephenville GT.
[29] 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, Hydro plans to retain both the Hardwoods GT and the Stephenville 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 the Hardwoods GT will be retired on the same schedule as the Holyrood TGS. 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. (“Newfoundland Power”), and Hydro’s own rural service territories.

4.2 Economic Setting

Newfoundland and Labrador’s economic growth was greatly affected by the global economic impacts of the COVID-19 pandemic in 2020 and it is expected to take several years for the economy to adjust.

In 2021, the provincial government forecasted rebounds for many economic measures including employment, real exports, capital investment, and real gross domestic product (“GDP”); however, most measures are forecast to remain below pre-COVID-19 pandemic levels until at least 2022.

The forecasted increase in real exports was largely a result of increased production by Tacora Resources Inc. in addition to higher oil and mineral prices. Reduced travel and health restrictions were also forecast to increase tourism and consumer spending, contributing to the forecast increases in real GDP and employment. Total household income in 2021 is expected to rise and forecasted provincial housing starts for 2021 are higher than 2020, indicating that the steep decline experienced is beginning to stabilize. Despite subdued activity within the provincial offshore oil sector, previously announced oil discoveries and longer-term exploration plans and programs bode well for a potential return to growth in this industry.

In 2020, as part of its response to the COVID-19 pandemic, NARL Refining LP temporarily suspended production at the refinery in Come by Chance. To date, the refinery has not restarted but the company has been supplying the local fuel market with available inventories and shipments from suppliers outside the province. In July 2021, a private equity firm entered into an agreement to purchase the refinery. While the sale is only an agreement in principle and remains pending at this time, optimism remains with respect to the future of the plant.

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 work on the project was slowed due to the COVID-19 pandemic, operations commenced this past July. In the fall of 2020, an Expression of Interest to establish salmon farming operations in two additional locations was released by the Department of Fisheries, Forestry and Agriculture. This continued 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. Additionally, Marathon Gold is progressing with its Valentine Gold Project in central Newfoundland, with operations expected to start in 2023.

On more broad-based economic terms over the medium term, adjusted real GDP is forecast to remain below pre-COVID-19 levels, being partially offset with increases in exports, driven by energy and mining projects. Population and employment levels are forecast to remain fairly consistent, while housing starts are forecast to remain stable but lower than previously experienced. Capital investment is also 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 2022, and growth will continue to be restrained through the medium term.

The current provincial government's fiscal situation remains relatively challenging and an overall weak economic environment exists. Underlying local market conditions for electric power operations suggest stable or possible decline in energy requirements in the short term followed by a return to increasing energy requirements in the longer term, which is primarily driven by actions to combat climate change resulting in a shift towards electrification.

4.3 Forecast Load Requirements

The customer load requirement component of Hydro's near-term load forecast was developed using forecasted load requirements provided by Hydro's industrial customers and Hydro's load forecast for Newfoundland Power and its rural service territories. Hydro relied on these inputs to determine a forecast of customer energy and coincident demand for the Island Interconnected System, the Labrador Interconnected System, and the Newfoundland and Labrador Interconnected System.

Changes in forecast load requirements since the filing of the May Report include changes in forecast Island Interconnected System power and energy requirements across the medium term. Forecast Island Interconnected System peak demand requirement changes in the short term are approximately 1.5% lower than previously forecast and less than 0.3% lower through the medium term, with forecast energy requirements modestly lower (0.5%) through the medium term. The reduction in forecast Island Interconnected System utility energy requirements primarily reflects changes to forecast energy requirements driven by a higher electricity rate forecast. Forecast power and energy requirements for the Island Interconnected System industrial customers are lower in the short term as a result of a change in the expectation of power requirements at the Come By Chance oil refinery, but remain consistent in the medium term with the expected start-up of Marathon Gold.

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 demand requirement is increased in 2022 compared to the May Report, following an earlier in-service date of synchronous condenser 3 at the Wabush Terminal Station. Forecast energy and demand requirements are also modestly higher (2% and 1%, respectively) through the medium term compared to the May Report as a result of increased industrial requirements.

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

Table 3: Island Interconnected System Peak Demand Forecast (MW)[30]

	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)[31]

	2022	2023	2024	2025
Utility[32]	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[33]	**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**

[30] Numbers may not add due to rounding.
[31] Numbers may not add due to rounding.
[32] The decline in utility requirements between 2022 and 2023 reflects the expiry of an existing contract with 77849 Newfoundland & Labrador Inc. (Carrying on Business as BlockLab).
[33] 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. In early 2021, Hydro established minimum storage limits to April 30, 2022 in consideration of the event that the LIL is unable to deliver energy to the Island Interconnected System for three months during winter 2022. 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 system.

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.

At this time, Hydro does not foresee using production from standby generation to support reservoir levels. 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.

At the end of October 2021, the total system energy in storage was 1,492 GWh, 437 GWh above the established minimum storage limit of 1,055 GWh. Figure 1 plots the 2020 and 2021 storage levels, maximum operating level storage, and the 20-year average aggregate storage for comparison.

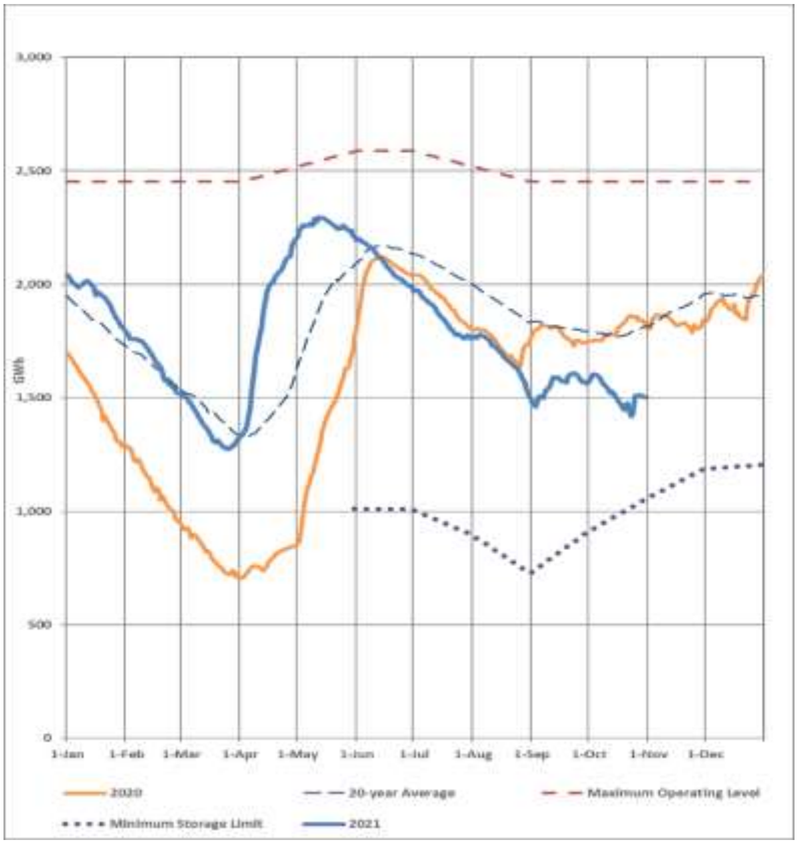

Figure 1: Total System Energy Storage for October 31, 2021

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

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 January 2022. 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.
- **Scenario 2**: Varies from Scenario 1 by increasing the Holyrood TGS DAFOR to 20%.
- **Scenario 3:** Varies from Scenario 1 by extending operation at the Holyrood TGS to March 31, 2024.

- **Scenario 4:** Varies from Scenario 2 by extending operation at the Holyrood TGS to March 31, 2024.
- **Scenario 5:** Assumes that the LIL will be available at a capacity of up to 312 MW for January 2022 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.
- **Scenario 6:** Varies from Scenario 5 by increasing the Holyrood TGS DAFOR to 18%.
- **Scenario 7:** Varies from Scenario 5 by increasing the Holyrood TGS DAFOR to 20%.
- **Scenario 8:** Varies from Scenario 1 by assuming that the LIL is not available through the study period (2022 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 9:** Varies from Scenario 8 by increasing the Holyrood TGS DAFOR to 18%.
- **Scenario 10:** Varies from Scenario 8 by increasing the Holyrood TGS DAFOR to 20%.
- **Scenario 11:** Varies from Scenario 10 by including 50 MW of imports during the winter season.
- **Scenario 12:** Varies from Scenario 10 by including 100 MW of imports during the winter season.

For Scenarios 8–12, 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 1–7, this remains unchanged. In Scenarios 8–12, 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, 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: Full LIL 2022, Holyrood TGS DAFOR = 15%	0.02	0.74	1.00	0.42
Scenario 2: Full LIL 2022, Holyrood TGS DAFOR = 20%	0.05	0.77	N/A	N/A
Scenario 3: Full LIL 2022, Holyrood TGS extended to March 31, 2024, DAFOR = 15%	0.02	0.02	0.28	N/A
Scenario 4: Full LIL 2022, Holyrood TGS extended to March 31, 2024, DAFOR = 20%	0.05	0.02	0.30	N/A
Scenario 5: LIL at 312 MW to June 2022, Holyrood TGS DAFOR = 15%	0.13	N/A	N/A	N/A
Scenario 6: LIL at 312 MW to June 2022, Holyrood TGS DAFOR = 18%	0.17	N/A	N/A	N/A
Scenario 7: LIL at 312 MW to June 2022, Holyrood TGS DAFOR = 20%	0.23	N/A	N/A	N/A
Scenario 8: No LIL, Holyrood TGS DAFOR = 15%	1.55	1.77	2.66	2.81
Scenario 9: No LIL, Holyrood TGS DAFOR = 18%	2.38	2.72	3.83	4.12
Scenario 10: No LIL, Holyrood TGS DAFOR = 20%	3.03	3.42	4.81	5.23
Scenario 11: No LIL, Holyrood TGS DAFOR = 20%, 50 MW imports	1.55	1.78	2.60	2.79
Scenario 12: No LIL, Holyrood TGS DAFOR = 20%, 100 MW imports	0.80	0.93	1.44	1.54

EUE (MWh)	2022	2023	2024	2025
Scenario 1: Full LIL 2022, Holyrood TGS DAFOR = 15%	1	70	97	35
Scenario 2: Full LIL 2022, Holyrood TGS DAFOR = 20%	2	67	N/A	N/A
Scenario 3: Full LIL 2022, Holyrood TGS extended to March 31, 2024, DAFOR = 15%	1	0	22	N/A
Scenario 4: Full LIL 2022, Holyrood TGS extended to March 31, 2024, DAFOR = 20%	2	2	25	N/A
Scenario 5: LIL at 312 MW to June 2022, Holyrood TGS DAFOR = 15%	6	N/A	N/A	N/A
Scenario 6: LIL at 312 MW to June 2022, Holyrood TGS DAFOR = 18%	9	N/A	N/A	N/A
Scenario 7: LIL at 312 MW to June 2022, Holyrood TGS DAFOR = 20%	11	N/A	N/A	N/A
Scenario 8: No LIL, Holyrood TGS DAFOR = 15%	82	94	146	157
Scenario 9: No LIL, Holyrood TGS DAFOR = 18%	131	147	223	233
Scenario 10: No LIL, Holyrood TGS DAFOR = 20%	166	192	285	305
Scenario 11: No LIL, Holyrood TGS DAFOR = 20%, 50 MW imports	79	93	142	153
Scenario 12: No LIL, Holyrood TGS DAFOR = 20%, 100 MW imports	38	43	72	77

NEUE (ppm)[34]	2022	2023	2024	2025
Scenario 1: Full LIL 2022, Holyrood TGS DAFOR = 15%	0.18	8.80	11.86	4.35
Scenario 2: Full LIL 2022, Holyrood TGS DAFOR = 20%	0.38	8.53	N/A	N/A
Scenario 3: Full LIL 2022, Holyrood TGS extended to March 31, 2024, DAFOR = 15%	0.18	0.11	2.86	N/A
Scenario 4: Full LIL 2022, Holyrood TGS extended to March 31, 2024, DAFOR = 20%	0.38	0.18	3.06	N/A
Scenario 5: LIL at 312 MW to June 2022, Holyrood TGS DAFOR = 15%	0.74	N/A	N/A	N/A
Scenario 6: LIL at 312 MW to June 2022, Holyrood TGS DAFOR = 18%	1.04	N/A	N/A	N/A
Scenario 7: LIL at 312 MW to June 2022, Holyrood TGS DAFOR = 20%	1.37	N/A	N/A	N/A
Scenario 8: No LIL, Holyrood TGS DAFOR = 15%	9.71	11.16	16.93	18.13
Scenario 9: No LIL, Holyrood TGS DAFOR = 18%	15.30	17.26	25.86	27.01
Scenario 10: No LIL, Holyrood TGS DAFOR = 20%	19.58	22.57	32.73	35.24
Scenario 11: No LIL, Holyrood TGS DAFOR = 20%, 50 MW imports	9.39	10.88	16.39	17.66
Scenario 12: No LIL, Holyrood TGS DAFOR = 20%, 100 MW imports	4.51	5.14	8.29	8.90

The results of Scenarios 1–7 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 the Holyrood TGS is retired, higher levels of LOLH and EUE are observed driven by the assumed higher FOR of the LIL in early years. In Scenarios 1 and 2, forecast levels of LOLH and EUE are beyond Hydro's planning criteria from late 2023 through 2024 as the Holyrood TGS has been retired and the LIL FOR continues to reflect the potential for operational unknowns. This is remedied by extension of operation of the Holyrood TGS to March 31, 2024, as evident in the results for Scenarios 3 and 4.

The results of Scenarios 8–10 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 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.[35] As demonstrated in Scenarios 11 and 12, 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

[34] 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.

[35] 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.

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.

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 1–7, 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. Further analysis of the monthly results indicates that once Holyrood TGS and the Hardwoods GT and Stephenville GT are retired in March 2023, higher levels of LOLH and EUE can be observed in the fall 2023 and winter 2024 months. 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. At that time, both LOLH and EUE meet Hydro's reliability standard. Monthly results for Scenarios 3 and 4 indicate that the extension of operation of the Holyrood TGS to March 31, 2024 brings the risk of lost load and unserved energy within planning criteria. 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.

Results from Scenarios 5–7 indicate that deliveries commensurate with those already experienced in commissioning would materially improve reliability. In Scenarios 8–10, the LOLH and EUE remain high throughout the study period, and without mitigation, indicate a relatively high probability of lost load on the system with no deliveries over the LIL.

As seen in Scenarios 11 and 12, 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.

Table 7: Monthly LOLH and EUE for 2022[36]

LOLH (hours)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
S1: Full LIL 2022, Holyrood TGS DAFOR = 15%	0.02	0	0	0	0	0	0	0	0	0	0	0
S2: Full LIL 2022, Holyrood TGS DAFOR = 20%	0.03	0.01	0	0	0	0	0	0	0	0	0	0.01
S3: Full LIL 2022, Holyrood TGS extended to March 31, 2024, DAFOR = 15%	0.02	0	0	0	0	0	0	0	0	0	0	0
S4: Full LIL 2022, Holyrood TGS extended to March 31, 2024, DAFOR = 20%	0.03	0.01	0	0	0	0	0	0	0	0	0	0.01
S5: LIL at 312 MW to June 2022, Holyrood TGS DAFOR = 15%	0.08	0.02	0.01	0	0	0	0	0	0	0	0	0.02
S6: LIL at 312 MW to June 2022, Holyrood TGS DAFOR = 18%	0.12	0.02	0.01	0	0	0	0	0	0	0	0	0.02
S7: LIL at 312 MW to June 2022, Holyrood TGS DAFOR = 20%	0.16	0.03	0.02	0	0	0	0	0	0	0	0	0.02
S8: No LIL, Holyrood TGS DAFOR = 15%	0.93	0.24	0.11	0	0	0	0	0	0	0	0	0.27
S9: No LIL, Holyrood TGS DAFOR = 18%	1.41	0.38	0.18	0	0	0	0	0	0	0	0.01	0.4
S10: No LIL, Holyrood TGS DAFOR = 20%	1.75	0.5	0.24	0.01	0	0	0	0	0	0.01	0.01	0.51
S11: No LIL, Holyrood TGS DAFOR = 20%, 50 MW imports	0.96	0.21	0.1	0.01	0	0	0	0	0	0	0.01	0.26
S12: No LIL, Holyrood TGS DAFOR = 20%, 100 MW imports	0.5	0.11	0.04	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
S1: Full LIL 2022, Holyrood TGS DAFOR = 15%	1	0	0	0	0	0	0	0	0	0	0	0
S2: Full LIL 2022, Holyrood TGS DAFOR = 20%	2	0	0	0	0	0	0	0	0	0	0	0
S3: Full LIL 2022, Holyrood TGS extended to March 31, 2024, DAFOR = 15%	1	0	0	0	0	0	0	0	0	0	0	0
S4: Full LIL 2022, Holyrood TGS extended to March 31, 2024, DAFOR = 20%	2	0	0	0	0	0	0	0	0	0	0	0
S5: LIL at 312 MW to June 2022, Holyrood TGS DAFOR = 15%	4	1	0	0	0	0	0	0	0	0	0	1
S6: LIL at 312 MW to June 2022, Holyrood TGS DAFOR = 18%	6	1	1	0	0	0	0	0	0	0	0	1
S7: LIL at 312 MW to June 2022, Holyrood TGS DAFOR = 20%	8	1	1	0	0	0	0	0	0	0	0	1
S8: No LIL, Holyrood TGS DAFOR = 15%	52	11	5	0	0	0	0	0	0	0	0	14
S9: No LIL, Holyrood TGS DAFOR = 18%	82	19	8	0	0	0	0	0	0	0	0	22
S10: No LIL, Holyrood TGS DAFOR = 20%	104	24	11	0	0	0	0	0	0	0	0	27
S11: No LIL, Holyrood TGS DAFOR = 20%, 50 MW imports	53	9	4	0	0	0	0	0	0	0	0	13
S12: No LIL, Holyrood TGS DAFOR = 20%, 100 MW imports	25	5	2	0	0	0	0	0	0	0	0	6

[36] Monthly results may not add up to annual results due to rounding.

Table 8: Monthly LOLH and EUE for 2023

LOLH (hours)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
S1: Full LIL 2022, Holyrood TGS DAFOR = 15%	0	0	0	0.02	0.01	0.01	0	0	0	0.01	0.07	0.62
S2: Full LIL 2022, Holyrood TGS DAFOR = 20%	0.01	0	0	0.02	0.01	0.01	0	0	0	0.01	0.08	0.63
S3: Full LIL 2022, Holyrood TGS extended to March 31, 2024, DAFOR = 15%	0.01	0	0	0	0	0	0	0	0	0	0	0.01
S4: Full LIL 2022, Holyrood TGS extended to March 31, 2024, DAFOR = 20%	0.01	0	0	0	0	0	0	0	0	0	0	0.01
S5: LIL at 312 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
S6: LIL at 312 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
S7: LIL at 312 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
S8: No LIL, Holyrood TGS DAFOR = 15%	0.97	0.30	0.12	0	0	0	0.01	0	0	0	0.01	0.36
S9: No LIL, Holyrood TGS DAFOR = 18%	1.42	0.47	0.21	0.01	0	0	0.01	0	0.01	0	0.01	0.58
S10: No LIL, Holyrood TGS DAFOR = 20%	1.78	0.62	0.28	0.01	0	0	0.01	0	0.01	0	0.01	0.70
S11: No LIL, Holyrood TGS DAFOR = 20%, 50 MW imports	0.95	0.30	0.13	0.01	0	0	0.01	0	0	0	0.02	0.36
S12: No LIL, Holyrood TGS DAFOR = 20%, 100 MW imports	0.50	0.14	0.06	0.01	0	0	0.01	0	0	0	0.02	0.19

EUE (MWh)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
S1: Full LIL 2022, Holyrood TGS DAFOR = 15%	0	0	0	1	0	0	0	0	0	0	4	65
S2: Full LIL 2022, Holyrood TGS DAFOR = 20%	0	0	0	1	0	0	0	0	0	0	4	62
S3: Full LIL 2022, Holyrood TGS extended to March 31, 2024, DAFOR = 15%	0	0	0	0	0	0	0	0	0	0	0	0
S4: Full LIL 2022, Holyrood TGS extended to March 31, 2024, DAFOR = 20%	1	0	0	0	0	0	0	0	0	0	0	1
S5: LIL at 312 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
S6: LIL at 312 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
S7: LIL at 312 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
S8: No LIL, Holyrood TGS DAFOR = 15%	55	14	6	0	0	0	0	0	0	0	0	19
S9: No LIL, Holyrood TGS DAFOR = 18%	81	24	10	0	0	0	0	0	0	0	0	32
S10: No LIL, Holyrood TGS DAFOR = 20%	106	31	13	0	0	0	0	0	0	0	1	41
S11: No LIL, Holyrood TGS DAFOR = 20%, 50 MW imports	53	14	6	0	0	0	0	0	0	0	1	19
S12: No LIL, Holyrood TGS DAFOR = 20%, 100 MW imports	25	6	2	0	0	0	0	0	0	0	1	9

Table 9: Monthly LOLH and EUE for 2024

LOLH (hours)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
S1: Full LIL 2022, Holyrood TGS DAFOR = 15%	0.34	0.20	0.17	0.03	0	0	0	0	0	0	0.05	0.21
S2: Full LIL 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
S3: Full LIL 2022, Holyrood TGS extended to March 31, 2024, DAFOR = 15%	0.01	0	0	0.03	0	0	0	0	0	0	0.05	0.19
S4: Full LIL 2022, Holyrood TGS extended to March 31, 2024, DAFOR = 20%	0.01	0	0	0.03	0.01	0	0	0	0	0	0.05	0.2
S5: LIL at 312 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
S6: LIL at 312 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
S7: LIL at 312 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
S8: No LIL, Holyrood TGS DAFOR = 15%	1.62	0.38	0.22	0.01	0	0	0.02	0.01	0.01	0	0.02	0.37
S9: No LIL, Holyrood TGS DAFOR = 18%	2.32	0.58	0.32	0.01	0	0	0.02	0	0.01	0	0.03	0.54
S10: No LIL, Holyrood TGS DAFOR = 20%	2.88	0.74	0.41	0.02	0.01	0	0.02	0	0.01	0	0.04	0.68
S11: No LIL, Holyrood TGS DAFOR = 20%, 50 MW imports	1.58	0.38	0.19	0.02	0	0	0.02	0	0.01	0	0.05	0.35
S12: No LIL, Holyrood TGS DAFOR = 20%, 100 MW imports	0.87	0.18	0.10	0.02	0.01	0	0.02	0	0.01	0	0.05	0.18

EUE (MWh)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
S1: Full LIL 2022, Holyrood TGS DAFOR = 15%	38	21	15	2	0	0	0	0	0	0	3	18
S2: Full LIL 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
S3: Full LIL 2022, Holyrood TGS extended to March 31, 2024, DAFOR = 15%	0	0	0	2	0	0	0	0	0	0	3	17
S4: Full LIL 2022, Holyrood TGS extended to March 31, 2024, DAFOR = 20%	1	0	0	2	0	0	0	0	0	0	4	18
S5: LIL at 312 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
S6: LIL at 312 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
S7: LIL at 312 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
S8: No LIL, Holyrood TGS DAFOR = 15%	96	19	10	0	0	0	0	0	0	0	1	20
S9: No LIL, Holyrood TGS DAFOR = 18%	144	31	16	0	0	0	1	0	0	0	1	30
S10: No LIL, Holyrood TGS DAFOR = 20%	180	41	20	1	0	0	1	0	0	0	2	40
S11: No LIL, Holyrood TGS DAFOR = 20%, 50 MW imports	93	18	9	1	0	0	1	0	0	0	2	18
S12: No LIL, Holyrood TGS DAFOR = 20%, 100 MW imports	47	8	4	1	0	0	1	0	0	0	2	9

Table 10: Monthly LOLH and EUE for 2025

LOLH (hours)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
S1: Full LIL 2022, Holyrood TGS DAFOR = 15%	0.17	0.09	0.06	0.01	0	0	0	0	0	0	0.02	0.07
S2: Full LIL 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
S3: Full LIL 2022, Holyrood TGS extended to March 31, 2024, 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: Full LIL 2022, Holyrood TGS extended to March 31, 2024, 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
S5: LIL at 312 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
S6: LIL at 312 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
S7: LIL at 312 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
S8: No LIL, Holyrood TGS DAFOR = 15%	1.67	0.43	0.22	0.01	0	0	0.02	0.01	0.01	0	0.02	0.42
S9: No LIL, Holyrood TGS DAFOR = 18%	2.35	0.69	0.36	0.01	0	0	0.02	0.01	0.01	0.01	0.03	0.63
S10: No LIL, Holyrood TGS DAFOR = 20%	2.93	0.92	0.47	0.02	0.01	0	0.03	0	0.01	0.01	0.05	0.78
S11: No LIL, Holyrood TGS DAFOR = 20%, 50 MW imports	1.61	0.45	0.21	0.02	0.01	0	0.02	0	0.01	0.01	0.05	0.40
S12: No LIL, Holyrood TGS DAFOR = 20%, 100 MW imports	0.89	0.22	0.09	0.02	0.01	0	0.02	0.01	0.01	0.01	0.05	0.21

EUE (MWh)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
S1: Full LIL 2022, Holyrood TGS DAFOR = 15%	15	8	5	0	0	0	0	0	0	0	1	6
S2: Full LIL 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
S3: Full LIL 2022, Holyrood TGS extended to March 31, 2024, 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: Full LIL 2022, Holyrood TGS extended to March 31, 2024, 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
S5: LIL at 312 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
S6: LIL at 312 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
S7: LIL at 312 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
S8: No LIL, Holyrood TGS DAFOR = 15%	99	22	10	0	0	0	1	0	0	0	1	24
S9: No LIL, Holyrood TGS DAFOR = 18%	144	35	18	0	0	0	1	0	0	0	1	34
S10: No LIL, Holyrood TGS DAFOR = 20%	184	49	23	1	0	0	1	0	0	0	2	45
S11: No LIL, Holyrood TGS DAFOR = 20%, 50 MW imports	96	22	9	1	0	0	1	0	0	0	2	22
S12: No LIL, Holyrood TGS DAFOR = 20%, 100 MW imports	49	9	4	1	0	0	1	0	0	0	2	11

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, 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 the Stephenville GT, retiring these assets 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. 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. For the upcoming winter, Hydro has established minimum storage limits which consider the possibility of three months of unavailability of the LIL. 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.