newfoundland labrador
hydro
a nalcor energy company

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, 2017

The 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 Corporate Services & Board Secretary

Dear Ms. Blundon:

Re: Newfoundland and Labrador Hydro - the Board's Investigation and Hearing into Supply Issues and Power Outages on the Island Interconnected System - Near-term Generation Adequacy Report – November 2017

Further to the Board's 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 the original plus 12 copies of Newfoundland and Labrador Hydro's report entitled "Near-term Generation Adequacy Report".

Hydro would also like to inform the Board that there was an issue today with Holyrood Thermal Generating Station Unit 1 and the unit was taken offline at 1:30 pm. There is an equipment failure, involving a pump and valve failure on lines connected to the condenser flash tank manifold and condenser flash tank. Hydro continues to have the necessary reserves required to meet demand, as is outlined in today's Supply and Demand Report. The investigation into Unit 1 is ongoing and Hydro estimates that the unit will return to service prior to the morning peak. Further updates will be provided as the investigation progresses.

Should you have any questions, please contact the undersigned.

Yours truly,

NEWFOUNDLAND AND LABRADOR HYDRO

Michael Ladha
Legal Counsel & Assistant Corporate Secretary
ML/skc

Encl.

cc: Gerard Hayes – Newfoundland Power
Paul Coxworthy – Stewart McKelvey Stirling Scales
Dennis Browne, Q.C. – Consumer Advocate
Danny Dumaresque

ecc: Roberta Frampton Benefiel – Grand Riverkeeper® Labrador
Larry Bartlett – Teck Resources Ltd.
Denis Fleming- Cox & Palmer

REGISTERED PROFESSIONAL ENGINEER PEGNL Newfoundland and Labrador DAVID R. GOOSNEY SIGNATURE Nov 15, 2017 DATE NEWFOUNDLAND & LABRADOR	Electrical
	Mechanical
	Civil
	Protection & Control
	Transmission & Distribution
	Telecontrol
	System Planning

Near-term Generation Adequacy Report

November 15, 2017

A Report to the Board of Commissioners of Public Utilities

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1 Executive Summary

Hydro has conducted an assessment of its overall asset health and a subsequent risk assessment of its ability to meet Island Interconnected System energy and demand requirements until the expected interconnection with the North American grid. Hydro's analysis considers a range of forecast scenarios and varying levels of equipment availability.

From both a demand and energy perspective, based on Hydro's asset reliability and in consideration of its energy in storage, Hydro remains confident in its ability to meet Island Interconnect System (IIS) customer requirements. Hydro has conducted a thorough assessment of its assets and the potential risks to the reliable operation of key generation assets, reflected in the projections of availability metrics based on historical data and the anticipated impact of planned improvements.

Hydro has taken actions to address repeated issues, including: broader reviews which frequently involved external experts, addressing issues with urgency, and an increased focus on asset reliability, as presented in this report. These actions are expected to enable continued reliable service this coming winter and in near term operating seasons.

Hydro recognizes that at times there are asset and system conditions that cause customers concern and require a focused effort to address to ensure adequate supply is available. In the event of any generation or transmission issue, from very short duration to longer duration, Hydro works to resolve the issue with urgency to ensure all generation and transmission is available to meet system requirements, inclusive of reserve.

Finally, it is important to note that the analysis presented in this report is conservative and includes both delayed interconnection to the North American grid and a P90 peak demand forecast. The scheduled in-service of the Maritime Link and the Labrador Island Link within the study period will increase reliability for Hydro's customers further bolster Island Interconnected System (IIS) reliability.

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2 Introduction

This report, titled *Near-Term Generation Adequacy Report* addresses Hydro's capability to provide adequate supply to its Island Interconnected System (IIS) customers by meeting peak demand and energy requirements. This report is filed semi-annually, on May 15 and November 15 of each year through interconnection. Hydro's previous assessment was filed with the Public Utilities Board (the Board) on May 15, 2017.

Following interconnection, Hydro intends to provide the Board with annual updates on its supply adequacy in a manner consistent with the previously *published "Generation Planning Issues Report"*, last issued in November 2012.

3 Island Interconnected System Overview

Hydro is the primary generator of electricity in Newfoundland and Labrador. Hydro's statutory mandate is provided in subsection 5(1) of the *Hydro Corporation Act*, 2007 as follows:

> *The objects of the corporation are to develop and purchase power on an economic and efficient basis … and to supply power, at rates consistent with sound financial administration, for domestic, commercial, industrial or other uses in the province…*

Hydro operates nine hydroelectric generating stations, one oil-fired plant, four gas turbines and twenty-five diesel plants. The Company's transmission, distribution and customer service activities include the operation and maintenance of over 3,500 kilometers of transmission lines and 3,400 kilometers of distribution lines. Hydro serves one large utility customer, Newfoundland Power, five regulated industrial customers, and over 38,000 direct residential and commercial customers.

Hydro's current service areas include: the Island Interconnected System (IIS); the Labrador Interconnected System (LIS); the L'Anse au Loup System; and isolated diesel communities in Labrador and on the Island. The primary focus of this report is the IIS.

3.1 Generation and Transmission Infrastructure – Current State

The IIS is primarily characterized by large hydroelectric generation capability located off the Avalon Peninsula and bulk 230 kV transmission lines extending from Stephenville in the west to St. John's in the east. Part of this system is comprised of two parallel 230 kV lines, TL 202 and TL 206, which bring energy to the Avalon Peninsula where demand is concentrated. The Holyrood Thermal Generating Station (HTGS), a large oil-fired thermal generating plant, is also located on the Avalon Peninsula. Figure 1 presents a visual overview of Hydro's current generation and transmission infrastructure both on the island of Newfoundland and in Labrador.

Figure 1 Hydro's Generation and Transmission Infrastructure

3.2 Generation and Transmission Infrastructure – Future State

The construction of a third 230 kV transmission line, TL 267, between Bay d'Espoir and the Western Avalon terminal station is nearing completion. The new line will increase Hydro's capability to deliver power to the major load centre on the Avalon Peninsula. The planned in-service date for TL 267 is December 8, 2017.

Work is also underway on the construction and integration of the Muskrat Falls Project Assets. The Muskrat Falls Project includes an 824 megawatt hydroelectric generating facility at Muskrat Falls, the Labrador-Island Link (LIL) that will transmit power from Muskrat Falls to Soldiers Pond on the Avalon Peninsula, and the Maritime Link (ML) connecting Newfoundland and Nova Scotia, which is being constructed by Emera Inc. of Nova Scotia. This will provide the IIS with two interconnections to the North American Grid, to Nova Scotia through the ML and to Quebec through the LIL and the Labrador Transmission Assets (LTA).

Figure 2 presents a visual overview of Hydro's generation and transmission infrastructure following the completion of TL 267, Muskrat Falls Project, the LIL, and the ML.

Figure 2 Hydro's Generation and Transmission Infrastructure Post Interconnection

4 System Planning Criteria

4.1 Load Forecasting

Hydro bases its generation supply planning decisions on a P90 peak demand forecast.[1,2] The P90 peak demand forecast reflects an increase in demand over a normalized, or P50, peak demand forecast, typically resulting from severe wind and cold temperatures over a period of several days. The development of the P90 peak demand forecast for the medium term is an extension of Hydro's regularly prepared system operating load forecast.

Both P50 and P90 peak demand forecasts are important to consider when assessing system adequacy. The P50 forecast is the basis for the system operating load forecast and development of Hydro's energy forecast, while the P90 forecast is the basis for Hydro to assess its ability to reliably supply customers in instances of severe weather conditions.

4.2 Generation Planning Criteria

Hydro has established generation planning criteria for the IIS that determines the timing of generation source additions to meet customer demand. These criteria set the minimum level of capacity and energy installed on the IIS to ensure an adequate supply for firm demand. Hydro's Loss of Load Hours (LOLH)[3] and firm energy criteria have been in use for more than 35 years and in that period have been reviewed several times, most recently by Manitoba Hydro Incorporated, Ventyx, and Liberty Consulting. In addition, Hydro has adopted a reserve margin

[1] A P90 forecast is one in which the actual peak demand is expected to be below the forecast number 90% of the time and above 10% of the time. A P50 forecast is one in which the actual peak demand is expected to be below the forecast number 50% of the time and above 50% of the time, i.e. the average forecast.

[2] In accordance with direction in the Board's letter to Hydro regarding Investigation and Hearing into Supply Issues and Power Outages on the Island Interconnected System - "Directions further to the Board's Phase One Report", received October 13, 2016.

[3] LOLH is a statistical assessment of the risk that the System will not be capable of serving the System's firm load for all hours of the year.

criterion, as discussed in *Hydro's Response to the Phase I Report by Liberty Consulting*.[4] Hydro's generation planning criteria are as follows:

Capacity: The Island Interconnected System should have sufficient generating capacity to satisfy a Loss of Load Hours (LOLH) expectation target of not more than 2.8 hours per year.[5]

And

The Island Interconnected System should have sufficient generating capacity to maintain a minimum reserve of 240 MW at the P90 system peak.[6]

Energy: The Island Interconnected System should have sufficient generating capacity to supply all of its firm energy requirements with firm system capability.[7]

4.3 Transmission Planning Criteria

The transmission system on the island of Newfoundland is assessed and expanded based upon prescribed transmission planning criteria. The transmission planning criteria used by Hydro, and reviewed by the Board, are defined as follows:

1. In the event a transmission element is out of service (i.e. under n-1 operation), power flow in all other elements of the power system should be at or below normal rating;
2. For normal operations, the system is planned on the basis that all voltages be maintained between 95% and 105%; and

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[4] http://pub.nl.ca/applications/IslandInterconnectedSystem/files/corresp/NLH-Phase-I-Reply-Submission-re-Liberty-Group-Report-2015-02-06.pdf.

[5] For Hydro, an LOLH expectation target of not more than 2.8 hours per year represents the inability to serve all firm load for no more than 2.8 hours in an average year.

[6] The 240 MW reserve margin provides Hydro with the ability to withstand the most onerous single contingency (loss of HTGS Unit 1 or 2) while maintaining a spinning reserve of 70 MW.

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

3. For contingency or emergency situations, voltages between 90% and 110% are considered acceptable.

4.4 Combined Generation and Transmission Planning Outlook

Currently, Hydro uses LOLH, reserve margin, and Expected Unserved Energy (EUE)[8] to assess generation adequacy. Each measure has strengths and limitations and includes some aspects that the others do not. Generally, if there is correlation between the three measures it indicates a robust analysis.

As noted in Section 4.2, existing Generation Planning Criteria defines an LOLH target of 2.8 hours per year. In previous risk assessments, the correlation of LOLH and EUE determined that 300 MWh of EUE was approximately equivalent to an LOLH of 2.8.

Note that both LOLH and EUE are probabilistic assessments of system adequacy. These metrics provide an indication of the level of supply risk for the system. Results in excess of the expressed thresholds indicate an increased likelihood, but no guarantee, of loss of supply outside of the utility's accepted risk profile. Further, assessments of EUE or LOLH that indicate no violation of planning criteria do not mean that there is no risk of loss of load, but rather that the risk is within acceptable system limits.

For further discussions of results, please refer to Section 7.4.

5 Asset Reliability

On a quarterly basis, Hydro reports to the Board on the rolling 12-month performance of its units, including actual forced outage rates and their relation to: (a) past historical rates, and (b)

[8] Expected Unserved Energy (EUE) is a statistical prediction of the amount of load that is unable to be served due to a shortfall in either generation or transmission capacity. When compared to LOLH, EUE provides a better measure of the magnitude of outages rather than the frequency of outages.

the assumptions used in System Planning's assessment of generation adequacy (Hydro's *"Rolling 12 Month Performance of Hydro's Generating Units"* report). The most recent report was submitted on October 30, 2017, for the quarter ending September 30, 2017. These reports detail any unit reliability issues experienced in the previous 12 month period. Performance is discussed in comparison with the previous 12 month period, a year prior.

Hydro has taken actions to address repeated issues, including: broader reviews which frequently involved external experts, addressing issues with urgency, and an increased focus on asset reliability. These actions are expected to result in improved reliability this coming winter and in near term operating seasons.

The system reserves maintained by Hydro are intended to cover both load variations as well as generation or transmission operational issues. Reserves, spinning and non-spinning, will provide for improved reliability in the event of system issues. In the event of any generation or transmission issue, from very short duration to longer duration, Hydro works to resolve the issue with urgency to ensure all generation and transmission is available to meet system requirements, inclusive of reserve.

5.1 Factors Affecting Recent Historical Generating Asset Reliability

Hydro has reviewed the factors affecting generating unit reliability since its most recent Near-Term Generation Adequacy report, filed May 2017. This report provides updates on items as required and discusses additional items which may impact asset performance. The intention is to ensure issues affecting reliability have been appropriately addressed. Issues that are recurring in nature, if not managed properly, can have a significant impact on unit reliability. As such, they require an additional level of review and mitigation to ensure improved asset reliability. The discussion provided in Sections 5.1.1 through 5.1.3 provides an overview of the repeat or broader issues. Isolated equipment issues, for example those that occur once on a particular unit, are also investigated, with the root cause identified and corrected. These types of issues are considered in the selection of appropriate Deration Adjusted Forced Outage Rate

(DAFOR) and Derated Adjusted Utilization Forced Outage Probability (DAUFOP)/Utilization Forced Outage Probability (UFOP).

The following sections provide a description of issues, both asset and condition based, that have previously affected generating unit reliability, as well as the current status of those issues and the actions taken to mitigate against future reliability impacts. The scope is not limited to Hydro's assets (i.e. penstock, boiler tubes), but also considers environmental challenges facing Hydro's operations.

As part of this exercise, Hydro has identified the following areas of discussion, grouped by facility type:

1. Seven areas of discussion for its hydraulic facilities (Bay d'Espoir penstock 1, lightning, frazil ice, Bay d'Espoir Unit 7 vibration, Upper Salmon rotor key cracking, Hinds Lake bearing coolers and Cat Arm Spherical Valve Controls);
2. Seven areas of discussion for its thermal facilities (unit boiler tubes, variable frequency drives, air flow limitations due to normal boiler fouling during operating season, turbine control system, exciter controls, Unit 2 steam inlet flange, and Unit 2 cable tray fire); and
3. Four areas of discussion for its gas turbines (End A vibration at Stephenville, automatic voltage regulator at Hardwoods, stack issues at Hardwoods and Stephenville and combustion can failures at Hardwoods).

5.1.1 Hydraulic

5.1.1.1 Bay d'Espoir Penstock 1

Penstock 1 is a 50 year old buried penstock at the Bay d'Espoir plant serving both Units 1 and 2. Following two leaks in 2016 and subsequent significant refurbishment of deteriorated welds, the penstock was returned to service on November 30, 2016, in advance of winter 2016/2017.

Based on the findings from the investigation of the leaks in 2016, Hydro has revised its preventative maintenance program for penstock inspections to reduce the risk of future events. The 5 year inspection frequency has been reestablished for steel penstocks. Hydro has developed plans to inspect and refurbish other penstocks in the fleet, on a priority basis with the expanded scope of inspection.

Since 2016 the following inspections have been done:

- Inspection of the Hinds Lake penstock in fall of 2016, with no concerns identified;
- Inspection of Bay d'Espoir penstock 4 in 2016, with no concerns identified;
- Inspection and refurbishment of the penstock welds of Bay d'Espoir penstock 2 in 2017; and
- Inspection of penstock 3 at Bay d'Espoir in April 2017 with no concerns identified.

Future plans include:

- Refurbishment of the earth cover for Bay d'Espoir penstock 1 in 2018;
- Inspection of the Upper Salmon penstock in 2018;
- Inspection of the steel portions of the penstocks at Cat Arm and Paradise River in 2018;
- Inspection of the Snook's Arm penstock in 2019; and
- Inspection of the Granite Canal penstock in 2020.

On November 4th, 2017, Hydro experienced a third leak from Penstock 1 in the same area as the previous two leaks. This section was identified as the highest stress location on the penstock from a stress analysis performed after the previous failures. Building on the learnings from the previous leaks, Hydro has developed a more intensive intervention to remove the failed section of the penstock, replace this section with new steel, and install plates over the new sections to provide additional reinforcement. In addition, Hydro is accelerating the plans to install additional backfill for penstock #1 surrounding the high stress location. Hydro is also conducting a root cause analysis (TapRooT®) to gain a better understanding of any underlying issues to develop mitigating measures to reduce the likelihood of another failure.

5.1.1.2 Lightning

Some of Hydro's generating units connected to the IIS via radial transmission lines (such as Granite Canal (41 MW), Upper Salmon (84 MW), Cat Arm (127 MW), Hinds Lake (75MW), and Paradise River (8 MW)) are susceptible to tripping during lightning strikes to the transmission lines. While lightning is not considered to have a significant impact on unit reliability on an individual unit basis, Hydro continually assesses the impact of lightning on all units to determine if additional measures are possible and warranted to improve system reliability.

When a strike does result in a plant trip, there can be exposure for an underfrequency event on the IIS. Hydro is actively working to reduce the risk of such an event and improve reliability for customers by changing its operating practice. Energy Control Centre (ECC) operators use the real-time Lightning Tracking System application to monitor lightning activity near Hydro's transmission systems and generating stations. In instances where lightning is approaching a station or its connecting transmission line, the ECC operators will, wherever possible, take action to reduce the overall loading on the plant to a level below which would require underfrequency load shedding if a trip were to occur (typically 50 MW or less). This practice has helped Hydro better manage the IIS during lightning events resulting in a positive impact on customers' reliability by avoiding a number of underfrequency events.

TL 269 was placed in-service this summer. This provides an alternate connection to Granite Canal and Upper Salmon, reducing the risk of loss of supply due to a lightning event for these plants.

5.1.1.3 Frazil Ice

Frazil ice is soft or amorphous ice formed by the accumulation of ice crystals in water that is too turbulent to freeze solid. This type of ice builds at plant intakes, impacting the amount of water that can be drawn into the plant, thereby reducing the generating unit capability. In Hydro's experience, such conditions have previously resulted in unavailability of units at its hydraulic plants. Outages due to frazil ice have been less frequent in comparison to previous years. The relatively lower frequency is attributed to differing environmental conditions, as well as to improvements in detection systems. Hydro has undertaken a number of such improvements, including the replacement of water temperature sensors with more accurate devices that are more strategically located. This change provides improved data, enabling operators to better respond to frazil icing situations by making dispatch changes.

Hydro also optimizes the trashrack[9] differential alarm settings at its plants known to have increased likelihood of frazil icing. These plants include Hinds Lake, Upper Salmon, and Granite Canal. This provides Hydro with a better awareness of frazil ice levels, thereby providing the opportunity to de-ice the trashrack and avoid an extended outage of several days.

Finally, there has been a concerted effort by ECC operators to proactively manage frazil icing and subsequently reduce related unit trips. Operators closely monitor ice cover, water temperature, wind speed, and trashrack differential during frazil ice season. Unit dispatch is optimized to allow solid ice cover to form based on the operators' assessment of these parameters in conjunction with system conditions. This further reduces frazil ice risk.

Hydro did not experience a forced outage due to frazil ice in winter 2016/2017. This can be largely attributed to the extra attention placed on the condition monitoring and preventative actions taken to minimize the impacts of frazil ice.

Improvements to the frazil ice detection system at Granite Canal are part of the 2017/2018 Hydraulic Structures Refurbishment capital project. When completed in 2018, this project will

[9] The trashrack is generally a set of bars that is located at the intake and will act as a large filter to prevent large debris, such a tree branches, from entering the penstock and into the generating unit. Build up of "trash" (trees, etc.) or ice impedes water flow into the penstock and affects generation output.

improve the detection capabilities by including more parameters that will be better able to detect frazil ice conditions and thus prevent forced outages.

5.1.1.4 Bay d'Espoir Unit 7 Vibration

Historically, Unit 7 in Bay d'Espoir has had two generator loading zones that were operationally avoided as the vibration experienced in these zones had been found to cause damage or result in a unit trip. To address this issue, the generator guide bearing was replaced as part of the unit overhaul in 2016. Since the last report, Unit 7 has started a few times with consistently good vibration performance. While the unit still has a rough operating zone, not uncommon for hydraulic generating units, the vibration in the rough zone is well within acceptable operating levels. Hydro continues to monitor this situation and considers this issue to be resolved.

5.1.1.5 Upper Salmon Rotor Key Cracking

Upper Salmon is the second largest hydraulic generating unit on the island interconnected system at 84 MW. This generator has experienced fretting corrosion[10] in recent years, indicating movement between the rotor spider and rotor rim. Due to the floating rim design, some movement is expected; however, an overhaul, which is included as part of Hydro's 2018 capital plan, is required to check if the movement is greater than can be tolerated. The scope of this overhaul includes a refurbishment of the rotor to address this issue.

Until the planned refurbishment in 2018, left unchecked this issue would present a near term risk to operation of the Upper Salmon unit. More than desirable movement between the rotor spider and rotor rim can cause cracking of the rotor rim key welds. Recently, the frequency of cracked rotor rim key welds has been increasing. Initially, the cracked welds were limited to the larger rim keys that could be driven back in place and re-welded with limited risk to unit operation. In March 2017, one of the smaller rim keys on the top of the unit cracked and

[10] Fretting corrosion is a form of accelerated atmospheric oxidation which occurs at the interface of contact materials undergoing slight repeated movement. One of the most common causes of loss of structural integrity is the development and propagation of cracks. Fretting corrosion in the case of floating rims, can lead to cracks.

started to move from its position. If a key moves fully out of its slot, there is potential for the key to fall between the rotor poles and the generator stator which could result in catastrophic failure. To address this risk, in consultation with an Original Equipment Manufacturer (OEM) engineer, Hydro has increased the frequency of visual inspections of rim key welds. If broken welds are found, immediate action is taken to reweld.

Since the May 2017 Near-term Generation Adequacy report, cracked key welds were identified each time the unit was shut-down for inspection. During the August 2017 annual outage, an interim repair was performed on the rim keys with technical guidance from an OEM generator expert. After unit operation following the repair subsequent inspection showed no evidence of further fretting corrosion, or cracked welds. Hydro plans to inspect the unit again before the end of November to assess the situation in advance of the winter operating season. During rotor rim key inspections, any defects are repaired prior to returning the unit to service. Past experience has shown that these repairs can typically be performed in one or two days. This will allow Hydro to remedy any deficiencies prior to the winter operating season. Based on inspection outcomes to date, Hydro does not anticipate finding defects that require intervention. The outcome from the November inspection will determine if further action is required prior to the planned overhaul in 2018.

5.1.1.6 Hinds Lake Bearing Coolers

Hydro implemented a bearing cooler replacement program in recent years, with new coolers installed in several plants to date. The Hinds Lake unit (75 MW) contains six generator bearing coolers. Based on the history and consultation with the OEM, these coolers were targeted for purchase as critical spares in 2020.

In spring of 2017, leaks were experienced in the cooling system at the Hinds Lake plant, requiring pressure testing of all coolers. The testing revealed that three of six coolers were leaking. The damaged coolers were isolated from the system and Hydro completed testing on the reduced cooling capacity. Test results indicated the cooling from the three remaining coolers was adequate for winter ambient air and water temperatures.

Hydro has repaired the leaking coolers by plugging leaking tubes. All six bearing coolers have been in service since late May without experiencing further leaks. Hydro has purchased a full set of six spare coolers, expected on-site in early December 2017. The spare coolers will enable Hydro to replace existing coolers in 2018 in a planned manner. Hydro has also purchased an external cooler/filter that can provide the equivalent cooling capacity of two coolers. Work was performed during the November 2017 outage to enable a quick installation of the oil and cooling water lines in the event that this external cooler is required through the winter.

To improve the reliability of operation through this winter, Hydro pressure tested the in-service during the recent annual outage. All coolers passed the pressure test. This is an indication that they can be expected to operate reliably through the winter. As a contingency, should a leak be experienced through this winter, the unit can be shut down to identify, isolate and repair leaking cooler(s). If multiple failures occur, the external cooler can be placed in service to achieve the required cooling capacity.

5.1.1.7 Cat Arm Spherical Valve Controls

As part of Hydro's ongoing maintenance program, an upgrade of the spherical valve controls in Cat Arm is required. There is potential for existing valves to malfunction during unit trips. The primary risk occurs that if the plant is not staffed during the event of a trip. At the extreme, this could result in flooding on the lower levels of the plant. In 2017, a capital project was approved to replace the spherical valve controls on both units in Cat Arm. The work is scheduled to be completed in 2018.

Hydro conducted a risk mitigation session to appropriately address existing risks until such time as the replacement project is complete. Hydro is currently mitigating this risk in two ways:

1) When units are offline, Hydro has proactively scheduled valve exercising to ensure proper functionality until the controls are replaced.
2) Hydro is in the process of redirecting the spherical valve controls drain lines so that they are better able to handle the increased flows in the event that valves do not operate properly.

This issue has not resulted in any reliability issues to date.

5.1.2 Thermal

5.1.2.1 Unit Boiler Tubes

Each of the three thermal generating units at Holyrood Thermal Generating Station (HTGS) has a boiler that contains tubes. Due to the failure of some tubes and thinning walls in others, Hydro experienced both unit outages and unit de-ratings in winter 2015/2016. Affected tubes were replaced during annual planned unit outages in 2016, prior to the 2016/2017 winter season. During winter 2016/2017, there were no unit boiler tube related outages or deratings.

During the 2017 annual boiler maintenance outages, ultrasonic thickness surveys were completed on all three boilers. In Unit 1 and Unit 2, all results were acceptable for continued operation. In Unit 3, twenty-one reheater tube bends were identified that did not meet the minimum thickness for creep life, as recommended by Wood (formerly Amec Foster Wheeler) in 2016. These tube bends were refurbished during the 2017 outage, and all other bends in the same location were inspected and no further refurbishment is required. Hydro will continue to proactively monitor tubes during annual outages. If required, Hydro will complete targeted replacements annually.

To ensure the operational integrity of these units and to minimize loading stresses, Hydro has adapted its operating parameters for these units to operate at the maximum continuous rating

(MCR) of 170 MW for units 1 and 2 and 150 MW for unit 3 only when necessary. These units are now normally operated to a maximum of 150 MW for units 1 and 2 and 135 MW for unit 3.

5.1.2.2 Variable Frequency Drives

Forced draft fans provide combustion air required for boiler operation at HTGS. The Variable Frequency Drives (VFDs) were installed to vary the amount of air required based on generation need. This reduces auxiliary power requirements and results in fuel savings. Previous to winter 2016/2017 there had been operational issues with the VFDs resulting in unit trips and reduced unit output.

Throughout 2016, Hydro worked closely with Siemens, the OEM, to resolve the issues and improve the reliability of these drives. As a result, multiple aspects of the VFDs were modified and additional actions were taken to improve reliability. The VFDs operated reliably throughout the 2016/2017 operating season.

Hydro continues to work with Siemens in 2017 and completed preventive maintenance on all the drives during the annual outages. Hydro also implemented a spare part cycling strategy to reduce the likelihood of shelf-life failures by rotating spare parts through the operating equipment. This strategy better positions Hydro to quickly respond to issues with the VFDs, should such present.

5.1.2.3 Air Flow Limitations

Appropriate air flow is required to provide enough air for combustion, enabling units to provide full output. Units 1 and 2 boilers have experienced air flow limitations since 2015. These normally developing limitations gradually increase over time, and resulted in capacity restrictions of up to 60 MW, on occasion. Unit 3 has not experienced material air flow limitations such as those experienced on Units 1 and 2 because, due to design differences, the economizer[11] in this unit is much less prone to fouling, and the air heaters are slightly larger than the Unit 1 and Unit 2 air heaters. The economizer fouling was a causal factor for deratings due to air flow through winter 2016/2017.

To address air flow limitations, Unit 1 and 2 boiler tuning was completed in the fall of 2016 after the lower reheater sections had been replaced during the annual maintenance outage work completed on both units. When the units were returned to service after the outages and boiler tuning completed, Unit 2 was capable of full load operation. Unit 1 remained derated at 165 MW, higher than the maximum output of 155 MW before the reheater failures and subsequent derating to 120 MW that occurred in winter 2015/2016. Based on the results of the tuning, Hydro concluded the root cause of the air flow issues on both units is the additive effect of fouling[12] through various sections of the economizer, ducting, boiler, air heaters and flues, and air heater leakage.

Air flow restrictions and the associated unit ratings degraded through the 2016/2017 operating season. Hydro took action to limit the system impact by conducting air heater washes and additional sootblowing.[13] Air heater washing is possible during the operating season but requires a short (approximately 2 day) outage to complete. During the 2016/2017 operating season, Hydro completed several air heater washes in attempt to maintain the load capability of Unit 1 and Unit 2. The effectiveness of these washes in restoring unit output diminished with time as the rest of the boilers, including the economizer sections, continued to foul.

[11] The economizer is a heat transfer device within the boiler that captures waste heat from boiler flue gases and transfers it back to the boiler feedwater thereby increasing thermal efficiency of the unit.
[12] Fouling in this context refers to an accumulation of boiler ash and other similar debris in various components of the air and gas paths through the boiler and associated ducting. Fouling can reduce boiler performance by reducing heat transfer if the deposits accumulate on heat transfer surfaces, and by flow restrictions if the deposits accumulate in areas where the cross sectional flow area of air or gas is significantly impacted.
[13] Sootblowing refers to the periodic online cleaning of the boiler surfaces by injection steam back into the boiler unit.

To further restore unit capacity, the boilers required effective cleaning throughout. This was a primary focus for the 2017 boiler outages on Unit 1 and Unit 2. Prior to unit shut down for the 2017 outages, the boiler contractor performed a study of the problem to identify any other concerns that could be contributing to the air flow deficiencies. They concluded that boiler fouling (particularly in the economizer) and air heater fouling and leakage were the primary issues.

For the outages, the boiler contractor hired a boiler cleaning company that specialized in cleaning severely fouled boiler components using a dry-ice blasting technique. This was used to blast ash from the economizer tube sections. Thousands of pounds of ash were removed from each boiler economizer using this process. In addition, water washing of all sections of the boiler including the furnace walls was completed. Additional water washing of the economizers was completed after the dry-ice blasting, to remove as much ash as possible. On Unit 2, the dry-ice contractor returned to site with a specially developed water wash nozzle to fit the economizer tube sections. This was effective in removing more ash from the economizer. Unit 1 had already returned to service when this nozzle was developed and, as such did not receive this cleaning. This will be considered for Unit 1 as part of the annual outage work in 2018.

Other work was completed during the outages to improve air flow in the boilers. Some of the most significant activities were: an upgrade of the air heaters on both units to reduce air heater leakage and reduce lost air flow, upgrade of leaking expansion joints, cleaning of air heater heating element sections, installation of new heating element in the Unit 1 air heaters, upgrade of the off line water wash systems on both units to ensure effective air heater washes, and replacement of the Unit 2 steam coil air heaters.

Units 1 and 2 have been on line and operating to the normal operating levels of 150 MW each, later presented in Table 7. Full load testing of the units has not been possible up until the time of this report due to other issues that have limited loading on the units. Unit 2 is currently limited due to a safety valve issue that will be corrected in a short outage that is scheduled for

November 20-24, 2017. Also, a boiler tuning expert has identified a problem in the control systems of units 1 and 2 that could impact airflow control. This is currently being investigated. The capability of both units will be verified by load test once the above outages have concluded and the tuning exercise has been completed. Hydro anticipates completing these tests in advance of winter readiness and will update the Board in the Winter Readiness Report due to be filed in December 2017.

5.1.2.4 Turbine Control System (Mark V System)

There were no issues with this system component during the 2016/2017 operating season. Hydro continues to work with GE to bolster reliability. In addition, GE is delivering on-site training of Instrumentation staff on the Mark V system. This training will be delivered from December 11-15, 2017 and will greatly improve the ability of the HTGS Instrumentation Technicians to troubleshoot and correct failures, should they occur.

5.1.2.5 Exciter control systems

Each generating unit at HTGS has an excitation system that controls the unit output voltage, which contributes to maintaining an acceptable Island Interconnected System (IIS) voltage. The exciter consists of a control section, a power section, and a field breaker. These sections can be modified or replaced separately. The exciters for Unit 1 and Unit 2 were installed in 2000 and 1999, respectively. The Unit 3 exciter, installed in 1979 was replaced in 2013 with an Asea Brown Boveri (ABB) Unitrol 6080 system.

To ensure reliable operation of the units, the control sections of the exciters were replaced with the modern Unitrol 6080 equipment. Hydro applied for approval of this project through a supplemental Capital Budget Application, approved by the Board in Order P.U. 10(2017).

5.1.2.6 Unit 2 Steam Inlet Flange

A flange on the steam piping that leads to the upper control valves for Unit 1 and Unit 2 turbines allows for the piping to be separated when removing the upper half of the turbine shell during major turbine overhauls. Since 2014, there have been repeated steam leaks at this flange.

In December of 2016, after the development of a steam leak on Unit 2, the flange was sealed using a temporary compound to ensure reliable operation through the winter operating season to the annual unit outage, when a permanent fix could be installed. Previous attempts to address the leak included provisioning of custom designed gaskets and hiring of specialty bolting contractors in an attempt to resolve this issue.

Since there are no further plans to remove the upper half shells for turbine maintenance the flange was replaced with a welded solid pipe spool during the 2017 annual outage. The Unit 1 steam inlet flange has not been a recent problem, but there was one flange gasket failure in 2014. A pipe spool is on site for Unit 1 and will be installed during the 2018 outage.

5.1.2.7 Unit 2 Cable Tray Fire

On May 1, 2017, a section of flexible ducting on the boiler ignitor air system failed and separated. This allowed boiler gas to flow back through the ducting at which point heat from the gas ignited an adjacent cable tray. The fire was extinguished quickly and the unit was taken off line while repairs were completed.

To improve reliability, steel ducting was extended to shorten the required span of the flexible ducting. Upgraded ducting and clamps were installed to reduce the likelihood of recurrence. To further reduce system risk, Hydro completed the same upgrades on Unit 1 during its annual outage. The difference in design of Unit 3 meant the same work was not required for that unit.

5.1.3 Gas Turbines

Hydro continues to identify, investigate, and resolve reliability issues related to the operation of the Stephenville and Hardwoods gas (combustion) turbines (GT). While many reliability issues have been resolved since 2014, the age of the units and the use of the units for system support have resulted in additional items for Hydro to identify and manage. Hydro has completed an operation and maintenance review of these facilities with a focus on improving the reliability of these facilities until such time as they are retired, or replaced. Details of this review and progress of implementation were presented to the Board in Hydro's report titled *Gas Turbine Failure Analysis Recommended Actions Implementation Update,* filed July 4, 2017. A further update on progress will be provided in the upcoming Winter Readiness Report to be filed in December, prior to the 2017/2018 winter operating season. In addition, selected planned capital upgrades to critical systems are being executed to ensure reliable operation of these units until end of life.

The Holyrood Combustion Turbine has been operating reliably since it's in service in 2015. Hydro continues to actively monitor and manage its asset health and, as with any generator on the IIS, Hydro investigates any issue and implements corrective action. In 2017 Hydro engaged the OEM in a service contract. This service agreement will provide assistance to Hydro in ensuring continued reliable service from this unit.

Further, in the coming winter period Hydro is maintaining a second loaner engine that can be installed in either Hardwoods or Stephenville. This second engine is a full size 25 MW unit, and therefore, Hydro now has two loaner engines on the island, for a total of six available engines, in the event of an issue with any of the four required engines between Hardwoods and Stephenville.

5.1.3.1 End A Vibration at Stephenville

Hydro's gas turbines are equipped with a vibration detection system to protect from failures which exhibit at increasing vibration levels. Historically, the engine OEM, Rolls Royce, recommended the vibration limits for Stephenville End A be set higher than normally recommended. In 2016, the engine installed in Stephenville End A experienced a bearing failure and was sent to an overhaul facility for refurbishment. As a result of this failure, the vibration settings were reviewed and adjusted to comply with the normally recommended settings.

Upon the return of the refurbished engine in December 2016, the refurbished gas turbine was reinstalled in End A in Stephenville, where it experienced unacceptably high levels of vibration. This engine was removed and a loaner engine obtained from Alba Power was installed in January 2017. In March 2017, the loaner engine began experiencing unacceptable levels of vibration and was removed from service.

Hydro's initial investigation suggested there might be a problem with the Stephenville End A berth or support structures that was inducing an unacceptable level of vibration in the gas turbine. Investigation into the integrity of the foundation has determined that this was not a factor in the vibration of the unit.

Since the engine was removed from service, various capital upgrades were completed, including a change in the vibration measurement location. Since these upgrades were completed, the unit has been tested and the vibration was within acceptable limits throughout its load range and the unit has now been released for service.

5.1.3.2 Automatic Voltage Regulator at Hardwoods

The voltage being produced by the Hardwoods alternator is controlled by an automatic voltage regulator (AVR). The AVR sets the alternator voltage while operating in either generate or synchronous condense modes. In November 2016 and March 2017, the alternator tripped while operating in synchronous condense mode, as a result of system conditions. Upon investigation, it was determined that the AVR had entered a fault state as a result of the trip, which prevented the alternator from automatically synchronizing with the power system. Once the fault was investigated and cleared, the unit was returned to service.

Hydro continues to investigate the source of the synchronizing issues being experienced which result following a trip or shutdown of the generator. Further investigation of the issues to date has resulted in an improved method of returning the unit to service following a unit trip. The AVR manufacturer is scheduled to be on site in November to assist in the resolution of the unit synchronizing issue and to provide training to engineering and maintenance personnel related to the AVR and exciter. It is anticipated that the investigation will be completed and corrective actions implemented prior to the start of the 2017/2018 winter operating season. Updates will be provided as part of Hydro's Winter Readiness Report, to be filed with the Board in December 2017.

5.1.3.3 Stack Issues Hardwoods and Stephenville

Stack cracking issues were experienced at both Hardwoods and Stephenville facilities. Currently, stack cracking has been identified on End A at Stephenville. Stack repairs were made on both ends at Stephenville in 2016 as part of the refurbishment program, but additional cracking has occurred outside the repair area. Further investigation is planned with repair to be completed as required once the extent is determined. It is expected that these repairs will be completed prior to the winter operating season. Further repairs are planned on both ends at Hardwoods in 2018 as part of the capital refurbishment project. Updates will be provided as part of Hydro's winter readiness report, to be filed with the Board in December 2017.

5.1.3.4 Combustion Can Failures at Hardwoods

Two engines installed in Hardwoods experienced combustion can failures in 2017. In February, Hardwoods engine #202224 failed in service due to a lube oil leak internal to the engine. A borescope inspection completed post failure also identified an imminent combustion can failure, but prior to full failure which in the past, has occurred and caused material damage to the rest of the engine. In August, a planned borescope inspection of the engine identified another combustion can failure. In both cases, the can failure occurred at the location of riveted bands within the combustion can.

Both engines have been returned to the overhaul facility to have the combustion cans replaced with an upgraded combustion can which is of welded rather than riveted construction.

5.2 Selection of Appropriate Performance Ratings

5.2.1 Consideration of Asset Reliability in System Planning

As identified in Section 4, Hydro's asset reliability is a critical component in determining its ability to meet the System Planning criteria for the IIS. As an input to the generation planning process, Hydro uses specific indicators to represent the expected level of availability due to unforeseen circumstances.

In considering its supply adequacy, Hydro evaluated the health of generating units across all asset classes. Table 1 summarizes the projected availability for Hydro's generating assets considered in the assessment of generation adequacy. These projections of asset reliability include appropriate consideration of asset availability and deration, for example a short term deration of a HTGS unit requiring an air heater wash.

Table 1 Summarized Asset Reliability Metrics

Asset	Reliability Metric
Bay D'Espoir Hydraulic Units	DAFOR = 3.85%
Remaining Hydraulic Units	DAFOR = 0.73%
Holyrood Thermal Units	DAFOR = 14%
Holyrood Gas Turbine	DAUFOP = 5%
Stephenville Gas Turbine	DAUFOP = 30%
Hardwoods Gas Turbine	DAUFOP = 30%

In determining appropriate reliability metrics for its thermal units, hydraulic units, and standby units, Hydro reviewed the projected availability noted in its May 2017 Near-term Generation Adequacy report, which considered asset performance through winter 2016/2017, the efforts undertaken by Hydro in 2017 as part of its capital and operating programs, and the projected availability for near-term winter seasons (as discussed in Section 5.1 above). Hydraulic and thermal DAFORs remain consistent with those used in Hydro's May report. A discussion of gas turbine reliability can be seen in Section 5.2.2.

5.2.2 Discussion of the DAUFOP measure for gas turbine reliability

While Hydro has traditionally used Utilization Forced Outage Probability (UFOP) as the measure of reliability for its gas turbines, since its May report, Hydro has been evaluating the appropriateness of Derated Adjusted Utilization Forced Outage Probability (DAUFOP) as an alternative measure of gas turbine reliability.

DAUFOP is the probability that a generating unit will not be available due to forced outages or forced deratings when there is demand on the unit to generate. It is essentially the UFOP calculation adjusted to include the effect of deratings on a unit's availability. The calculation includes both outages that remove the unit from service completely and instances when units are de-rated.[14]

This measure is defined by the Canadian Electricity Association (CEA) and North American Electric Reliability Corporation (NERC) similarly. The DAUFOP calculation was developed from IEEE Standard 762-2006. The formula is as follows:

Formula:

$$DAUFOP\ (\%) = \frac{\{f(FO + FEMO + FEPO)\ + O(FD)adj\}}{f(FO + FEMO + FEPO) + O + O(FD) + O(SD)}$$

Where:

FO = number of hours the unit was in a forced outage state.

FEMO = the number of hours the unit was in a forced extension of a maintenance outage state.

[14] If a unit's output is reduced by more than 2%, the unit is considered de-rated by the Canadian Electricity Association (CEA) guidelines. Per CEA guidelines, to account for deration of a generating unit, the operating time at the de-rated level is converted into an equivalent outage time.

FEPO = the number of hours the unit was in a forced extension of a planned outage state.

O(FD) = the number of hours the unit was operating under a forced derating.

O = the number of hours the unit was in the operating state during the period.

O(SD) = the number of hours the unit was operating under a scheduled derating during the period.

O(FD)adj = the number of hours the unit was operating under a forced derating converted to an equivalent outage time. X is the percent derating of Maximum Continuous Rating (MCR)15.

$$O(FD)adj = \left(\frac{100 - X}{100}\right) * O(FD)$$

Hydro continues to use UFOP as a reliability measure for its GTs. UFOP is defined as the probability that a generating unit will not be available due to a forced outage when required to generate. This measure does not consider unit deratings, but rather assumes the unit is available at 100% of its capacity when required. Additionally, it only considers the hours that the unit is needed for operation. This metric may not provide an accurate reflection of the available level of generation that what can be counted on to support the IIS. For example, during previous operations at Hardwoods and Stephenville, engine failures have resulted in a 50% reduction in plant capacity. While this unavailability would impact the DAUFOP for either plant, it has no bearing on the calculated UFOP, as UFOP does not consider unavailability when the plant is not required.

Because the use of DAUFOP as an indication of GT reliability would reflect all periods where GT unit deratings impact available system generation, Hydro has decided to use DAUFOP as the basis for all of the analysis in this report. Based on the historical performance and age of the gas turbines a target of 30% for the DAUFOP will be used. In previous reports, Hydro has used a

[15] For example if a generating unit is derated to 80 percent of its MCR for 5 hours, that would be equivalent to a full outage of the generating unit for 1 hour.

UFOP of 20% for the Hardwoods and Stephenville GTs. For the purposese of this analysis, the 30% DAUFOP is more conservative than the 20% UFOP and results in a higher EUE and LOLH. Beginning in January 2018, Hydro will measure and track both UFOP and DAUFOP for its gas turbines.

6 Load Forecast

Hydro's load forecast for the Island Interconnected System is comprised of three components:

1. Customer requirement
2. Transmission loss requirement
3. Station service requirement

The customer requirement component of Hydro's five-year peak demand forecast is developed using forecasted load requirements provided by Newfoundland Power, Hydro's industrial customers, and Hydro's load forecast for its IIS rural service territory. Hydro relies on these inputs to determine a forecast of customer coincident demand for a five-year period. Transmission losses are determined by transmission system load flow analysis based on forecast customer coincident demand. Station service is the demand and subsequent energy consumed by Hydro's generating stations. In the existing Island Interconnected System, HTGS is the largest contributor to the IIS station service requirement. The primary reporting and system planning measure is the megawatt winter peak demand for the island's 60 Hz system.

Based on Hydro's assessment of the peak demand impact of more severe weather condition, the P90 peak demand forecast adds an additional 60 MW in customer coincident demand requirement over the P50 demand forecast[16]. For the winter 2017/2018 period, Hydro's transmission losses include transmission line TL 267. This asset is scheduled to be in service as of December 8, 2017. Should the in-service of TL 267 be delayed, there would be an increase of

[16] The 60 MW incremental demand was re-assessed prior to the Near-Term Generation Adequacy Report filed in May 2017.

10 MW over the 2017-18 winter P90 peak demand forecast for a total of a 70 MW increase over the P50 forecast peak demand.[17]

Liberty has recommended Hydro assess the impact of a 50 MW variation in the 2019-20 peak demand versus the forecast. It is Hydro's opinion that the analytical basis of the suggested +50 MW variation in demand has not been well founded[18]. Based on analysis done in the May 2017 Near-term Generation adequacy Report the average high-side forecast deviation for a peak demand forecast for one to four years into the future would be expected to be approximately 20 to 25 MW. This deviation is captured in Sensitivity Load Projection III.

As part of this risk assessment, Hydro has updated both its P50 and P90 peak demand forecasts to reflect the latest available customer and system information. The revised P90 forecast, including the contribution of each of the three components, is provided in Table 2. Information on Hydro's P50 forecast can be found in Appendix A.

Table 2 P90 Peak Demand Forecast

Base Case Winter Demand Forecast					
	P90				
	2017/2018	2018/2019	2019/2020	2020/2021	2021/2022
Customer Coincident Demand (MW)	1735	1727	1719	1706	1686
Transmission Losses (MW)	50	50	50	50	50
Station Service (MW)	24	24	24	24	24
Total Island Interconnected System Demand (MW)	**1808**	**1801**	**1792**	**1779**	**1760**

Note: Differences in totals vs addition of individual components due to rounding.

[17] It is noted that transmission losses are a function of two factors that include total system load and net power flow to the Avalon Peninsula. The incremental load associated with the P90 peak demand forecast includes more than 30 MW of load on the Avalon Peninsula. The increase in transmission losses is therefore attributed to both factors.

[18] Analysis done on the +50 MW case can be found in Appendix B.

6.1 Sensitivity Load Growth Scenarios

To ensure a robust assessment of risk, Hydro has considered sensitivity forecasts in addition to the base case forecast. The sensitivity forecasts being considered in this analysis are detailed below:

- Sensitivity Load Projection I - Stable utility demand: Assumes that while the energy requirements in the current forecast decline, demand requirements remain stable (i.e. lower load factor);
- Sensitivity Load Projection II – High customer coincidence: Includes increased industrial and utility load requirement over Hydro's base case expectation assuming less diversity in customer demand requirements at Island Interconnected System peak;
- Sensitivity Load Projection III – Assessed customer demand uncertainty: Includes high side uncertainty of 20-25 MW over one to four years based on past peak demand forecasts and actual weather normalized peak data; and
- Sensitivity Load Projection IV –Worst case forecast: Combines early forecast from Sensitivity Load Projection IV (winter 2017-18 through winter 2019-20) and later forecasts from Sensitivity Load Projection I (winter 2020-21 through winter 2021-22). Presents the most onerous combined forecast on considered scenarios.

The sensitivity forecasts are summarized in Table 4 and Table 5. For ease of comparison, the Base Case forecast is again provided in Table 3.

Table 3 P90 Peak Demand Forecast

Base Case Winter Demand Forecast					
	P90				
	2017/2018	2018/2019	2019/2020	2020/2021	2021/2022
Customer Coincident Demand (MW)	1735	1727	1719	1706	1686
Transmission Losses (MW)	50	50	50	50	50
Station Service (MW)	24	24	24	24	24
Total Island Interconnected System Demand (MW)	**1808**	**1801**	**1792**	**1779**	**1760**

Note: Differences in totals vs addition of individual components due to rounding.

Table 4 Alternative Load Growth Scenarios

	Sensitivity I: Stable Utility Demand					Sensitivity II: High Coincidence Factor				
	2017/ 2018	2018/ 2019	2019/ 2020	2020/ 2021	2021/ 2022	2017/ 2018	2018/ 2019	2019/ 2020	2020/ 2021	2021/ 2022
Customer Coincident Demand (MW)	1735	1734	1733	1732	1732	1754	1745	1737	1724	1704
Transmission Losses (MW)	50	50	50	50	50	50	50	50	50	50
Station Service (MW)	24	24	24	24	24	24	24	24	24	24
Total Island Interconnected System Demand	**1808**	**1808**	**1807**	**1807**	**1806**	**1827**	**1819**	**1811**	**1798**	**1778**

Note: Differences in totals vs addition of individual components due to rounding

Table 5 Alternative Load Growth Scenarios Continued

	Sensitivity III: High Utility Uncertainty					Sensitivity IV: Worst Case Scenario				
	2017/ 2018	2018/ 2019	2019/ 2020	2020/ 2021	2021/ 2022	2017/ 2018	2018/ 2019	2019/ 2020	2020/ 2021	2021/ 2022
Customer Coincident Demand (MW)	1755	1748	1741	1730	1711	1755	1748	1741	1732	1732
Transmission Losses (MW)	50	50	50	50	50	50	50	50	50	51
Station Service (MW)	24	24	24	24	24	24	24	24	24	24
Total Island Interconnected System Demand	**1829**	**1822**	**1815**	**1805**	**1785**	**1829**	**1822**	**1815**	**1807**	**1807**

Note: Differences in totals vs addition of individual components due to rounding

7 System Constraints and Future Supply Risk

To fully understand the potential supply risk posed to the Island Interconnected System in advance of North American grid interconnection, detailed transmission, hydrological, and generation system analysis were required.

7.1 System Energy Capability

Reservoir inflows have been below normal up to the end of October. For 2017 to date, inflows are 87% of normal. Weather conditions experienced in the fall of 2017 on the island have been dry, where as typically multiple weather systems during fall result in heavy rain which adds substantially to Hydro's reservoir storage. October 2017 was the third lowest inflow in Hydro's record dating back to 1950. Further, Hydro's weather consultant, Wood (formerly Amec Foster Wheeler), is expecting below normal precipitation to continue through the late fall and early winter.

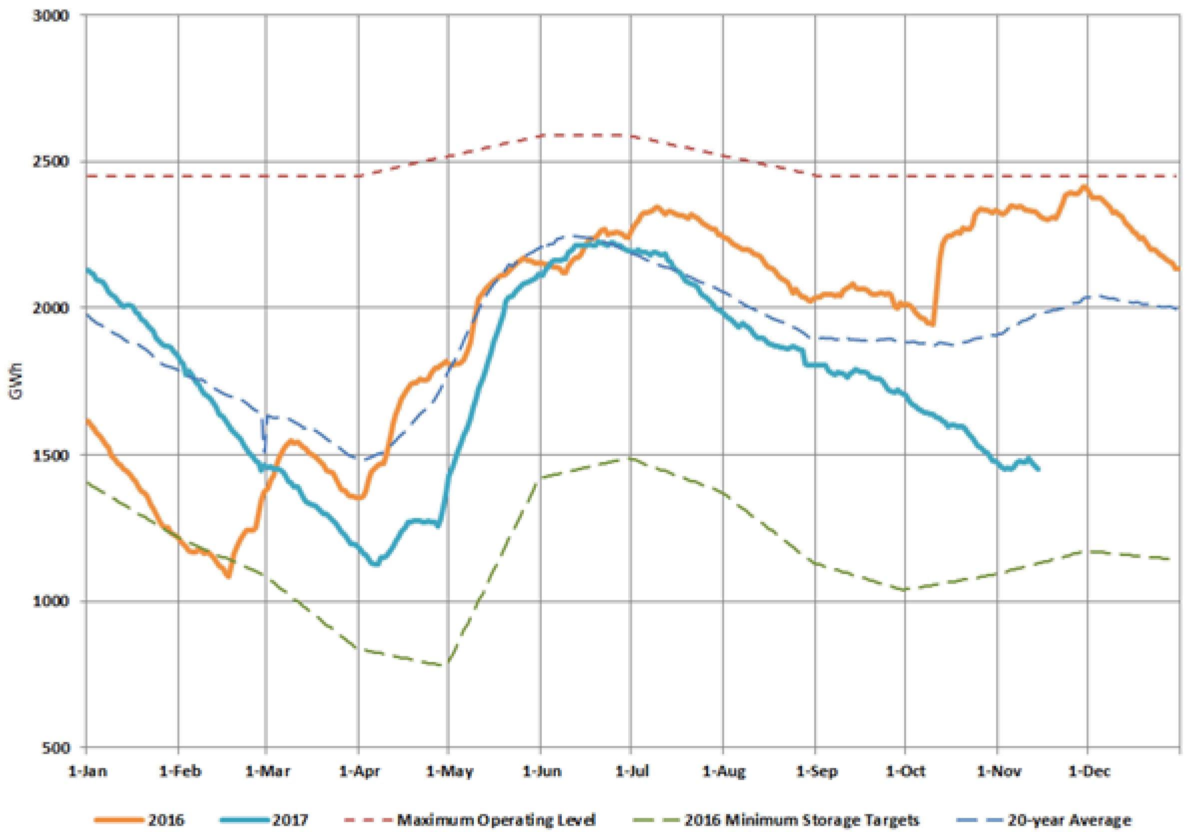
Table 6 2017 Inflows vs. Average

System Inflows			
Month	2017	Average (GWh)	Average (%)
January	214	312	68%
February	127	263	48%
March	233	292	80%
April	632	599	106%
May	1116	891	125%
June	423	421	100%
July	95	209	45%
August	146	187	78%
September	182	234	77%
October	107	349	31%
November	N/A	473	N/A
December	N/A	427	N/A

Note: N/A denotes not available

As shown in Figure 3, Hydro's aggregate storage at the end of October the storage level was 1480 GWh, 60% of Maximum Operating Level.

Figure 3 Total System Energy Storage



During October, as part of Hydro's water management process, Hydro's Resource and Production Planning Department recommended an increase in thermal generation at HTGS to reduce generation from the hydraulic system for the driest historic inflow sequences modelled. As Hydro continued its analysis, increasingly more historic sequences showed the need for additional thermal generation. In order to be proactive, Hydro increased thermal generation starting on November 2, 2017. It is the intent to keep thermal generation above minimum until the decline in hydraulic energy storage slows or reverses and analysis indicates the requirement for less thermal generation. Hydro will continue to report on available system energy as part of its *Energy Supply Report*, submitted monthly to the Board.

7.2 Transmission System Analysis

System capacities under various operating scenarios were quantified and exposures for unserved energy were investigated. Hydro's base case transmission planning analysis now includes the in-service of TL 267.

7.2.1 The Avalon Transmission System

Demand on the Avalon Peninsula is supported by the following sources of supply:

- Thermal generation from: HTGS Units, Holyrood Gas Turbine, Hardwoods Gas Turbine, and Holyrood Diesels;
- Hydraulic Generation from Newfoundland Power Units;
- Thermal Generation from Newfoundland Power's mobile diesel generator;
- Diesel Generation at Vale Terminal Station;
- Capacity Assistance from Vale Newfoundland & Labrador Limited (Vale);
- Capacity Assistance from Praxair Canada Inc. (Praxair);
- Wind Generation;[19] and
- 230 kV transmission lines TL 203, TL 237, and TL 267 at the Western Avalon Terminal Station.

7.2.2 Transmission System Analysis Results

Load flow analysis confirms that there are no violations of Transmission Planning criteria, as defined in Section 4.3, for worst case based on the reference case assumptions.

7.2.3 Extended Transmission Planning Analysis

An extended Transmission Planning analysis was performed to assess the exposure for unserved energy for various operating scenarios beyond the scope of Transmission Planning criteria. These scenarios included consideration of loading conditions and outages to multiple units on the Avalon Peninsula.

[19] Wind generation is not considered to be online in this analysis as it is not considered to have firm capability.

For the purposes of this analysis, it was assumed that the HTGS thermal units are operating at their gross continuous unit ratings, and the recommendations of Hydro's Asset Management team as discussed in section 5.1.2.

Once TL 267 is in service in December 2017, transmission constraints on the Avalon Peninsula are eliminated to the extent that the loss of two HTGS units will not result in transmission system violations. Rather, the loss of two HTGS units over system peak would result in a shortfall of generation for the IIS. With the loss of two HTGS units, the total IIS capacity is limited to approximately 1700 MW. Similarly, total IIS capacity is limited to approximately 1410 MW when three HTGS units are out of service.

7.3 Generation Planning Analysis

To determine the potential risk posed to the IIS from a generation capacity perspective, Hydro performed analysis to determine the impact on expected unserved energy (EUE; MWh), reserve margin (MW), and loss of load hours (LOLH; hours) criteria of:

1. Thermal generation availability based on projected DAFORs, UFOPs and DAUFOPs;
2. Hydraulic generation availability based on projected DAFOR; and
3. Revised peak demand forecast including sensitivities.

Additionally, in its report titled *"Evaluation of Pre-Muskrat Falls Supply Needs and Hydro's November 30, 2016 Energy Supply Risk Assessment Final Report",* The Liberty Consulting Group (Liberty) asked that Hydro provide the Board with a brief report considering the impact on expected unserved energy (EUE) for the following cases:

1. HTGS DAFOR = 20%;
2. CT UFOP = 30% and 50%;
3. 50 MW variation in 2019-20 peak demand versus the forecast; and
4. Two-year delay in Muskrat Falls.

The results for case 3 and the second half of case 2 are available in Appendix B: Considerations as per Liberty's Evaluation of Pre-Muskrat Falls Supply Needs and Hydro's November 30, 2016 Energy Supply Risk Assessment Final Report. Results for cases 1, 2 and 4 are in fact embedded throughout this report, as with the exception of the Expected Case, all analysis has been done on the basis of continued isolated island operation, meaning no interconnection to the North American grid via either the Labrador Island Link (LIL) or the Maritime Link (ML), through winter 2021-22. This represents a further two year delay in in-service.

7.3.1 Expected Case Parameters

The Expected Case reflects Hydro's anticipated system capability and P90 demand forecast with scheduled in-service dates of the Labrador Island Link and Maritime Link. The following assumptions were used to develop the Expected Case for this analysis:

1. The study period is defined as winter 2017/2018 through winter 2021/2022 inclusive.
2. Key in-service dates:
    a. TL 267: Available for the 2017-18 winter peak.
    b. The Labrador Island Link, the Maritime Link, and the Soldiers Pond Synchronous Condensers: In-service and available for the 2019-2020 winter peak.
3. For the duration of the study period, the only power available for import over the LIL would be firm recall power from Labrador at a capacity of 110 MW at Soldiers Pond, available for winter 2018/2019 and beyond.
4. For conservatism, this analysis considers no import over the ML, though the ML will be in-service and available. As such, its availability has no impact on results presented herein.
5. For peak load operation, all Hydro and Newfoundland Power thermal generation is available and dispatched to maintain acceptable reserve levels for the IIS and the Avalon Peninsula.
6. Curtailable loads are assumed available as follows:
    - Corner Brook Pulp and Paper – 90 MW
    - Newfoundland Power – 9.9 MW (9 MW on the Avalon Peninsula)

- Vale – 6 MW
- Praxair – 5 MW

7. HTGS units are rated in accordance with Table 7.

Table 7 HTGS Unit Ratings

	Rating (MW)		
	Unit 1	Unit 2	Unit 3
Normal Operation	150	150	135
Maximum Operation	170	170	150

8. All other units rated in accordance with Hydro's expected operating conditions.

7.3.2 Fully Stressed Reference Case

The Fully Stressed Reference Case is a conservative analysis reflecting Hydro's anticipated capacity in consideration of the P90 peak demand forecast should no interconnection to the North American grid be established through winter 2021/2022.

In the Fully Stressed Reference Case it is assumed that the Labrador Island Link, the Maritime Link, and the Soldiers Pond Synchronous Condensers are not in service. As such, for the duration of the study period, no power can be imported over the LIL or ML.

In addition to the Base Peak Demand Forecast, Hydro performed additional analysis on the Fully Stressed Reference Case with the four sensitivity load growth scenarios discussed in Section 6.2.

7.4 Results

7.4.1 Reserve Margin Analysis

Reserve margins for the Expected Case, Fully Stressed Reference Case, and the four sensitivity load projections are presented in in Table 8. The Fully Stressed Reference Case with Sensitivity

Load Projection IV is the most onerous scenario presented in Table 8. Reserve margins remain at or in excess of the 240 MW criterion for all cases considered.

Table 8 Reserve Margin Analysis

Island Interconnected System P90 Demand Forecast Reserve Margin Analysis					
	Winter 2017-18	Winter 2018-19	Winter 2019-20	Winter 2020-21	Winter 2021-22
Expected Reference Case					
A: IIS Forecast Peak Demand	1,808	1,801	1,792	1,779	1,760
B: Less Available Capacity Assistance (111 MW)[1]	1,697	1,690	1,681	1,668	1,649
C: Capacity at Peak[2]	1,992	1,997	2,107	2,107	2,107
Reserve Margin (MW) (C-B)	294	307	425	439	458
Reserve Margin (%)	17%	18%	25%	26%	28%
Fully Stressed Reference Case					
A: IIS Forecast Peak Demand	1,808	1,801	1,792	1,779	1,760
B: Less Available Capacity Assistance (111 MW)[1]	1,697	1,690	1,681	1,668	1,649
C: Capacity at Peak[2]	1,992	1,997	1,997	1,997	1,997
Reserve Margin (MW) (C-B)	294	307	315	329	348
Reserve Margin (%)	17%	18%	19%	20%	21%
Fully Stressed Reference Case with Sensitivity Load Projection I					
A: IIS Forecast Peak Demand	1,808	1,808	1,807	1,807	1,806
B: Less Available Capacity Assistance (111 MW)[1]	1,697	1,697	1,696	1,696	1,695
C: Capacity at Peak[2]	1,992	1,997	1,997	1,997	1,997
Reserve Margin (MW) (C-B)	294	300	301	301	301
Reserve Margin (%)	17%	18%	18%	18%	18%
Fully Stressed Reference Case with Sensitivity Load Projection II					
A: IIS Forecast Peak Demand	1,827	1,819	1,811	1,798	1,778
B: Less Available Capacity Assistance (111 MW)[1]	1,716	1,708	1,700	1,687	1,667
C: Capacity at Peak[2]	1,992	1,997	1,997	1,997	1,997
Reserve Margin (MW) (C-B)	275	288	297	310	330
Reserve Margin (%)	16%	17%	17%	18%	20%
Fully Stressed Reference Case with Sensitivity Load Projection III					
A: IIS Forecast Peak Demand	1,829	1,822	1,815	1,805	1,785
B: Less Available Capacity Assistance (111 MW)[1]	1,718	1,711	1,704	1,694	1,674
C: Capacity at Peak[2]	1,992	1,997	1,997	1,997	1,997
Reserve Margin (MW) (C-B)	274	285	292	303	323
Reserve Margin (%)	16%	17%	17%	18%	19%
Fully Stressed Reference Case with Sensitivity Load Projection IV					
A: IIS Forecast Peak Demand	1,829	1,822	1,815	1,807	1,807
B: Less Available Capacity Assistance (111 MW)[1]	1,718	1,711	1,704	1,696	1,696
C: Capacity at Peak[2]	1,992	1,997	1,997	1,997	1,997
Reserve Margin (MW) (C-B)	274	285	292	301	301
Reserve Margin (%)	16%	17%	17%	18%	18%

1. Capacity Assistance based on amount available in 2016-17 and the new CBPP Capacity Assistance Agreement approved in Board Order P.U. 34(2017). Availability tests for 2017-18 to be completed by November 30, 2017
2. Adjusted to reflect Hydro's anticipated installed capacity, including the winter 2017-18 deration of Exploits resultant from the Grand Falls Unit 4 outage and the availability of the Holyrood Diesels at 8.5 MW.

7.4.2 EUE and LOLH Analysis

The Expected Case results, contained in Table 9, indicate no violations of the planning criteria in the winter of 2017/2018 at the expected HTGS DAFOR, with violations in the LOLH and EUE resulting for increased HTGS unavailability. The EUE and LOLH decrease significantly in subsequent years as the availability of the surplus recall power to the IIS mitigates the risk presented by the loss of multiple units at HTGS given the current load forecasts.

Table 9 Expected Case

Summary of Results					
P90 Analysis					
Year	**2017-18**	**2018-19**	**2019-20**	**2020-21**	**2021-22**
HRD DAFOR	**Expected Unserved Energy (MWh)**				
14%	201	11	-	-	-
15%	241	14	12	-	-
20%	520	31	28	23	17
	Expected Customer Outage Hours				
14%	33,400	1,900	1,700	1,400	900
15%	40,300	2,200	2,000	1,700	1,200
20%	86,700	5,200	4,500	3,800	2,800
	LOLH				
14%	2.12	0.41	0.36	0.28	0.20
15%	2.44	0.49	0.43	0.34	0.24
20%	4.44	0.99	0.88	0.71	0.51

Note:
Planning Criteria is EUE = 300 MWh; Annual Expected Outage Hours = 50,000; LOLH = 2.80

EUE and LOLH for the Fully Stressed Reference Case, the four sensitivity load projections[20] is presented in Table 10 through 15. To provide more insight into the degree of uncertainty in variables and conclusions, results are provided for HTGS DAFORs of 14%, 15%, and 20%. By providing results for a 1% increase in plant DAFOR (HTGS DAFOR = 15%) and a severe plant

[20] A discussion of the Load Growth Scenarios can be found in Section 6.1.

DAFOR (HTGS DAFOR = 20%), the impact of DAFOR on EUE is more readily apparent. Note that a 20% DAFOR at HTGS can be compared to having a unit unavailable at HTGS three of every five days. Hydro maintains that the projected plant DAFOR of 14% is reasonable and based on thorough analysis.

Table 10 Fully Stressed Reference Case

Summary of Results					
P90 Analysis					
Year	2017-18	2018-19	2019-20	2020-21	2021-22
HRD DAFOR	Expected Unserved Energy (MWh)				
14%	201	168	155	136	111
15%	241	202	186	163	134
20%	520	439	406	358	296
	Expected Customer Outage Hours				
14%	33,400	27,900	25,700	22,700	18,500
15%	40,300	33,600	31,100	27,100	22,400
20%	86,700	73,100	67,700	59,700	49,300
	LOLH				
14%	2.77	2.47	2.20	1.82	1.35
15%	3.17	2.83	2.53	2.10	1.57
20%	5.66	5.10	4.58	3.87	2.97

Note:
Planning Criteria is EUE = 300 MWh; Annual Expected Outage Hours = 50,000; LOLH = 2.80

Table 11 Sensitivity Load Projection I: Stable Utility Demand

Summary of Results					
P90 Analysis					
Year	2017-18	2018-19	2019-20	2020-21	2021-22
HRD DAFOR	Expected Unserved Energy (MWh)				
14%	201	180	179	178	179
15%	241	216	215	214	215
20%	520	469	466	463	466
	Expected Customer Outage Hours				
14%	33,400	30,000	29,800	29,700	29,800
15%	40,300	36,000	35,700	35,700	35,700
20%	86,700	78,200	77,500	77,400	77,500
	LOLH				
14%	2.77	2.72	2.71	2.67	2.71
15%	3.17	3.12	3.10	3.06	3.10
20%	5.66	5.58	5.52	5.48	5.55

Note:
Planning Criteria is EUE = 300 MWh; Annual Expected Outage Hours = 50,000; LOLH = 2.80

Table 12 Sensitivity Load Projection II: High Coincidence Factor

Summary of Results					
P90 Analysis					
Year	2017-18	2018-19	2019-20	2020-21	2021-22
HRD DAFOR	Expected Unserved Energy (MWh)				
14%	242	202	186	163	134
15%	290	242	223	196	162
20%	620	521	483	427	354
	Expected Customer Outage Hours				
14%	40,400	33,700	31,100	27,300	22,200
15%	48,300	40,400	37,300	32,600	26,900
20%	103,400	86,900	80,500	71,100	59,100
	LOLH				
14%	3.58	3.20	2.86	2.36	1.79
15%	4.08	3.66	3.27	2.71	2.07
20%	7.15	6.46	5.80	4.90	3.82

Note:
Planning Criteria is EUE = 300 MWh; Annual Expected Outage Hours = 50,000; LOLH = 2.80

Table 13 Sensitivity Load Projection III: Assessed Customer Demand Uncertainty

Summary of Results					
P90 Analysis					
Year	**2017-18**	**2018-19**	**2019-20**	**2020-21**	**2021-22**
HRD DAFOR	**Expected Unserved Energy (MWh)**				
14%	246	207	194	175	144
15%	294	249	232	210	174
20%	628	535	502	455	380
	Expected Customer Outage Hours				
14%	40,900	34,400	32,400	29,000	24,100
15%	48,900	41,400	38,600	34,900	28,800
20%	104,600	89,300	83,600	76,000	63,200
	LOLH				
14%	3.67	3.33	3.02	2.60	1.98
15%	4.18	3.80	3.45	2.98	2.29
20%	7.31	6.70	6.10	5.35	4.19

Note:
Planning Criteria is EUE = 300 MWh; Annual Expected Outage Hours = 50,000; LOLH = 2.80

Table 14 Sensitivity Load Projection IV: Worst Case Forecast

Summary of Results					
P90 Analysis					
Year	**2017-18**	**2018-19**	**2019-20**	**2020-21**	**2021-22**
HRD DAFOR	**Expected Unserved Energy (MWh)**				
14%	246	207	194	178	179
15%	294	249	232	214	215
20%	628	535	502	463	466
	Expected Customer Outage Hours				
14%	40,900	34,400	32,400	29,700	29,800
15%	48,900	41,400	38,600	35,700	35,700
20%	104,600	89,300	83,600	77,400	77,500
	LOLH				
14%	3.67	3.33	3.02	2.67	2.71
15%	4.18	3.80	3.45	3.06	3.10
20%	7.31	6.70	6.10	5.48	5.55

Note:
Planning Criteria is EUE = 300 MWh; Annual Expected Outage Hours = 50,000; LOLH = 2.80

For the analysis conducted, results are similar to those presented by Hydro in it's May report. The analysis indicates that there are no violations of the LOLH and EUE criteria for the Expected Case, with the availability of 110 MW of firm Recapture energy over the Labrador Island Link expected for Winter 2018-19, as well as the Fully Stressed Case, which considers no interconnection to the North American grid through the entire study period, with the base forecast when the HTGS DAFOR is 14%. Minor violations of the criteria are present in the Fully Stressed Reference Case only for LOLH at 15% DAFOR and both LOLH and EUE at the severe 20% DAFOR.

Consistent with results presented in Hydro's May report, HTGS DAFORs of 14% and 15% do not result in violations of the EUE criterion. Violations of the EUE criterion only occur for the severe HTGS DAFOR of 20%. Additionally, there are violations of the LOLH criterion only when the HTGS DAFOR is in excess of 14%. It is important to note that the Sensitivity Projections are done on the Fully Stressed Reference Case, which is a conservative analysis using the P90 peak demand forecast reflecting no interconnection to the North American grid within the period being analyzed, reflecting a further delay of in service of both the Maritime Link and the Labrador Island link of 3.5 years. In service of the LIL, currently scheduled for mid-2018, and the availability of recapture energy fully mitigates the identified risk, as demonstrated in the Expected Case results.

8 Conclusion

Hydro has conducted an assessment of its overall asset health and a subsequent risk assessment of its ability to meet IIS energy and demand requirements until the expected interconnection with the North American grid. In all of the scenarios considered there was sufficient generation to meet system peak demand requirements and satisfy system planning criteria. It is important to note that the analysis presented in this report is conservative and includes a delay in interconnection and P90 weather conditions. The scheduled in-service of the Maritime Link and the access it provides to the North American grid will further bolster IIS reliability.

From an energy perspective, based on Hydro's asset reliability and in consideration of the critical dry sequence, Hydro remains confident in its ability to meet IIS energy requirements. However, due to lower than expected inflows in the summer and fall months, Hydro has increased thermal generation to supplement hydraulic generation.

From a demand perspective, Hydro has conducted a thorough assessment of its assets and the potential risks to the reliable operation of key generation assets. Hydro has also determined reasonable projection for availability metrics based on historical data and the anticipated impact of planned improvements. Hydro has evaluated the benefits of both DAUFOP and UFOP and plans to use both as reliability measures for the gas turbines going forward. Further, in addition to the base forecast, Hydro constructed four sensitivity demand forecasts to examine the effects of different load growth projections.

Hydro has taken actions to address repeated issues, including: broader reviews which frequently involved external experts, addressing issues with urgency, and an increased focus on asset reliability, as presented in this report. These actions are expected to result in continued reliable service this coming winter and in near term operating seasons.

The system reserves maintained by Hydro are intended to cover both load variations as well as generation or transmission operational issues. Reserves, spinning and non-spinning, will provide for improved reliability in the event of system issues. In the event of any generation or transmission issue, from very short duration to longer duration, Hydro works to resolve the issue with urgency to ensure all generation and transmission is available to meet system requirements, inclusive of reserve.

Appendix A

P50 Forecast Analysis

P50 Peak Demand Forecast

As part of this analysis, Hydro has updated both its P50 and P90 peak demand forecasts to reflect the latest available customer and system information. The revised P50 forecast, including the contribution of each of customer coincident demand, transmission losses, and station service is provided in Table 15.

Table 15 P50 Peak Demand Forecast

Base Case Winter Demand Forecast					
	P50				
	2017/2018	2018/2019	2019/2020	2020/2021	2021/2022
Customer Coincident Demand (MW)	1675	1667	1658	1645	1626
Transmission Losses (MW)	49	49	49	49	49
Station Service (MW)	24	24	24	24	24
Total Island Interconnected System Demand (MW)	**1747**	**1739**	**1731**	**1718**	**1698**

Note: Differences in totals vs addition of individual components due to rounding

Appendix B

Additional Analysis Requested as part of Liberty's report titled

Evaluation of Pre-Muskrat Falls Supply Needs and Hydro's November 30, 2016

Energy Supply Risk Assessment

Table 16 Addition of 50 MW to peak demand for 2019-20 to the end of the study period

Summary of Results					
P90 Analysis					
Year	2017-18	2018-19	2019-20	2020-21	2021-22
HRD DAFOR	Expected Unserved Energy (MWh)				
14%	201	168	382	337	281
15%	241	202	454	401	335
20%	520	439	946	842	711
	Expected Customer Outage Hours				
14%	33,400	27,900	63,700	56,100	46,900
15%	40,300	33,600	75,600	66,900	55,900
20%	86,700	73,100	157,500	140,400	118,300
	LOLH				
14%	2.77	2.47	4.32	3.65	2.79
15%	3.17	2.83	4.90	4.15	3.19
20%	5.66	5.10	8.41	7.26	5.69

Note:
Planning Criteria is EUE = 300 MWh; Annual Expected Outage Hours = 50,000; LOLH = 2.80

Table 17 50% DAUFOP Case for Hardwoods and Stephenville Gas Turbines on Fully Stressed Reference Case

Summary of Results					
P90 Analysis					
Year	2017-18	2018-19	2019-20	2020-21	2021-22
HRD DAFOR	Expected Unserved Energy (MWh)				
14%	307	258	238	209	173
15%	367	308	285	251	208
20%	779	660	613	543	454
	Expected Customer Outage Hours				
14%	51,200	42,900	39,700	34,700	28,700
15%	61,000	51,300	47,600	41,800	34,600
20%	129,900	110,000	102,300	90,500	75,400
	LOLH				
14%	3.59	3.20	2.86	2.37	1.77
15%	4.09	3.65	3.27	2.72	2.04
20%	7.14	6.45	5.78	4.91	3.77

Note:
Planning Criteria is EUE = 300 MWh; Annual Expected Outage Hours = 50,000; LOLH = 2.80