NEWFOUNDLAND AND LABRADOR
BOARD OF COMMISSIONERS OF PUBLIC UTILITIES
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Re: Newfoundland and Labrador Hydro - 2017 General Rate Application Information Item #16 - The Liberty Consulting Group Report: Analysis of Newfoundland Island Interconnected System Power Supply Adequacy for the Winter of 2018-19

Further to the Board's letter dated August 31, 2018 in relation to The Liberty Consulting Group Report: *Analysis of Newfoundland Island Interconnected System Power Supply Adequacy for the Winter of 2018-19*, please be advised that the Board is entering this report as part of the hearing record of Newfoundland and Labrador Hydro's 2017 General Rate Application as Information Item#16 for the information of the parties.

If you have any questions please do not hesitate to contact the undersigned or the Board's Legal Counsel, Ms. Jacqui Glynn, e-mail, jglynn@pub.nl.ca or telephone (709) 726-6781.

Sincerely,

C Blundon

Cheryl Blundon
Board Secretary

CB/cj

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Analysis of Newfoundland Island Interconnected System Power Supply Adequacy for the Winter of 2018-19

Presented to:

The Board of Commissioners of Public Utilities
Newfoundland and Labrador

Presented by:

The Liberty Consulting Group

August 30, 2018

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I. Analysis of Newfoundland Island Interconnected System Power Supply Adequacy for the Winter of 2018-19

A. Executive Summary

As requested by the Board of Commissioners of Public Utilities (the Board), this report provides Liberty's analysis of near-term power supply adequacy and observations on the changing operating and supply situation as the Labrador Island Link (LIL) and Muskrat Falls (MF) approach operations.

Power supply vulnerability has become a problem for the Island Interconnected System (IIS) in recent years as winter approaches. The nature of the threat may change each year, but the exposure to supply-related outages persists. This year, delays in the reliable in-service date of the LIL and their impacts on anticipated supply from Labrador (known as recall power), and poor performance at the Holyrood Thermal Generating Station (TGS)increases the risk of supply related outages considerably.

Hydro and Nalcor representatives were unwilling to provide information about LIL schedule details sufficient to permit us to identify a realistic LIL in-service date. Nevertheless, what we have learned supports a conclusion that the LIL is unlikely to be reliably in commercial operation at the start of the winter. We have further concluded that, once accepted into commercial operation, the LIL is likely to prove somewhat unreliable, due to: (1) its planned operation as a monopole in its first year, (2) continuing problems with one of its primary vendors, General Electric (GE), (3) the limited duration of the minimum successful run required for acceptance (20 days versus 60 on many other such projects), and (4) the typical problems associated with any new facility in its early operation, especially one whose technology is new to the owner.

Power Supply Outlook

	Favorable	Unfavorable

Winter 2018-19	• Recall power
	• New import contract
	• Weak load forecast
	• ML and frequency control
	• TL 267
		• The LIL
		  • Delayed in-service date
		  • Reliability of the monopole
		• Condition of fleet, especially Holyrood

Assuming reliable LIL operation, supply versus load margins appear more than adequate, but loss of the LIL removes 214 MW from the supply equation (110 MW of recall power and 104 MW in a firm import contract). That substantial loss produces violations of Newfoundland and Labrador Hydro's (Hydro) 2.8 LOLH reliability criterion, even assuming reasonably dependable performance from the generation fleet. Unfortunately, experience makes an assumption of dependable performance inappropriate. Management assumes a Holyrood TGS DAFOR of 20 percent in one of its sensitivity cases, which produces an LOLH for the winter of 6.19 when the LIL is not in service, well above the 2.8 criterion. Moreover, while 20 percent reflects a high DAFOR, we believe that it still understates the risks.

A rapid change of circumstances has brought Hydro, in just several months, from more-than-adequate supply to violations of its reliability criteria and heightened risk. Management had consistently reported that the LIL would indeed be available for the winter, but there is now a strong possibility that will not be the case. Liberty therefore recommends that the Board require Hydro to aggressively demand and monitor action by Nalcor to ensure that Nalcor undertakes all possible actions to minimize further delays in placing the LIL into reliable operation for this coming winter, while at the same time preparing contingency plans for the unavailability or limited reliability of the LIL. Given the unacceptable trends in Holyrood performance, we are also recommending more aggressive action by Hydro to improve its asset management program and capabilities.

B. Introduction and Background

The Board has required periodic analyses from Hydro, and has periodically asked Liberty to evaluate the supply situation, including review and analysis of the Hydro reports. Key documents over the last two years, each of which has significance to this current report, include:

- Liberty's "Review of Newfoundland and Hydro Power Supply Adequacy and Reliability Prior to and Post Muskrat Falls – Final Report" dated August 19, 2016, and also known as Liberty's Phase 2 Report. This report raised concerns about the need for new generation both pre- and post-MF.
- Hydro's "Energy Supply Risk Assessment" (ESRA) dated November 30, 2016. This ESRA addressed pre-MF supply needs and, while discussing a wide variety of supply issues, concluded the pre-MF supply was more than adequate.
- Liberty's "Evaluation of Pre-Muskrat Falls Supply Needs and Hydro's November 30, 2016 Energy Supply Risk Assessment – Final Report" dated February 27, 2017. This evaluation cited three major ESRA assumptions that improved the pre-MF supply outlook, and significantly tempered our concerns: (1) the addition of 110 MW of recall power, (2) an AMEC report providing a more optimistic outlook on resolution of Holyrood's 2016 operating problems, and (3) another large drop in forecasted peak demand.
- Three reports by Hydro titled "Near-term Generation Adequacy Report" dated May 15, 2017, November 15, 2017 and May 22, 2018 (Revised May 30, 2018) respectively. These reports provided periodic updates of the pre-MF supply situation to the Board. The most recent report presents a positive pre-MF outlook with more-than-adequate margins for the winter of 2018-19.

The general theme of all these reports has been a brightening picture on near-term supply (pre-MF). Liberty has generally concurred with that increasingly optimistic outlook; however, factors coming to light recently reduce confidence that winter 2018-19 margins will prove sufficient, to the extent that the reliability criteria will not be met, thereby heightening the risk of outages.

C. Power Supply Reliability Criteria

The importance of a reliable power supply requires rigorous, quantified determinations of adequacy. Appropriate methods can reflect many uncertainties, but it remains that ground rules, techniques and applied assumptions be well-defined and uniformly applied. Flexibility in making choices can exist, but after setting the criteria, one should expect compliance with them.

For decades, Hydro has employed a criterion of 2.8 loss of load hours (LOLH) in planning its electric system. LOLH estimates the average number of hours in a year that Hydro would be unable to serve firm load. Hydro's 2.8 LOLH corresponds to a loss of load expectation (LOLE) of 0.2, or two events every ten years.

Other measures of outage probability included in Hydro's analyses, and their corresponding values, include:

- Expected Unserved Energy (EUE): 170 MWh per year
- Expected Customer Outage Hours: 28,000 hours per year.

We find the EUE target especially interesting in that management has revised it downward this year - - from 300 in prior years. The reduction resulted from the change to the PLEXOS model, which presumably produces a more accurate estimation. The change affects the historical analysis of EUEs presented in our above-referenced 2016 Phase 2 report. That analysis described actual EUE performance as exceeding criteria in four of the five years ending 2015, including the impact of non-supply-related events. Considering supply-related causes alone, EUE was above the new level in four of the last five years, and six of the last nine years.

Hydro's primary reliability criterion (LOLH) has remained the same for many years, but management has changed many other elements of its methods for calculating LOLH, especially since the system events of 2014. Perhaps the most significant of these was a shift to more conservative weather assumptions. Planners assume a given set of weather conditions in order to estimate the peak load expected in a coming winter. Hydro examines a list of annual worst temperatures over a period of many years and selects the value (the "temperature variable") that encompasses 90 percent of the points. This approach equates to only a 10 percent chance that the worst temperature in the coming winter will be less than the selected value. That value is known as the P90 forecast. Until 2015, Hydro had regularly used a P50 forecast, meaning that the annual worst temperature would be lower than forecast every other year.

Hydro has also adopted less optimistic estimates of generating unit reliability in its supply adequacy calculations. This change reflects the continuing decline in the condition of the thermal fleet, primarily the Holyrood TGS and the Hardwoods and Stephenville combustion turbines (CTs).

In addition, management has adopted new software, PLEXOS, to model the system and calculate LOLH. PLEXOS, which is in widespread industry use, is thought to be a major upgrade and system improvement.

It is reasonable therefore to conclude that Hydro's supply analysis, from a calculational perspective versus its reliability criteria, remains as strong as ever and has become more conservative than it was prior to 2014.

1. Significance of, and Tolerance for, Violations

One might tend to take comfort in the more conservative nature of today's analyses, even to the extent of minimizing the significance of violations. We do not consider that to be an acceptable approach. There is a great deal of flexibility in deciding upon criteria, assumptions and calculational techniques, but after setting the ground rules, one should not change them simply because they result in a violation.

For example, one might assert that the uncertain nature of the planning processes and the uncertainties inherent in so many of the assumptions suggest that minor changes in LOLH (say 3.4 versus 2.8) do not raise material concern. An LOLH of 2.8 does not imply an outage-free winter, and an LOLH of 3.4 does not imply an outage-prone winter. If actual temperatures remain well above the temperature variable used, peak loads will be low, thereby minimizing supply-related outages even for higher LOLHs. Similarly, higher than expected generation unit availability makes supply more ample, again minimizing supply-related outages. We can conclude therefore that, while a higher LOLH increases the risks of outages, that risk may remain relatively low and criteria violations may not raise substantial concern.

But this logic has a flaw when applied under circumstances like those of the IIS. We believe that criteria violations may have existed in all of the last five winters. Operating under such increased risk conditions might prove harmless in any given winter, but not on a continuing basis. Potential supply deficiencies, as manifest in higher LOLH, must be addressed each year, and not simply dismissed, since the models tell us convincingly that at some point a high price will be paid.

Our Interim April 24, 2014 Report, our first on Hydro's operations, observed (at page 19) that Hydro operated "near the edge," and it appears to still do so. Perhaps this concern of operating near the edge will go away with the completion of MF. This question should get a definitive answer in a major supply report from Hydro in November 2018. For now, we recommend treatment of all violations as important, with multiple years of continuing violations being particularly problematic.

D. Winter 2018-19 Supply Outlook

At first glance, the supply picture for the coming winter appears excellent, with margins higher than those seen for many years on the Island of Newfoundland, as illustrated in the table below. The "contracted supply case" in the table includes the added 104 MW in the new import contract.

	Conservative Supply Case	Contracted Supply Case
IIS Forecast Peak Demand	1,789	1,789
Capacity at Peak	2,101	2,205
Plus Available Capacity Assistance (100 MW)	2,201	2,305
Reserve Margin (MW)	412	516
Reserve Margin (%)	23.0%	28.8%

As expected, the outage parameters, LOLH, EUE and expected customer outage hours, all fall within their respective criteria by about a factor of ten. The highlights of this very favorable supply picture include a P90 peak demand forecast of 1,789 MW. This forecast for Winter 2018-19 has dropped by 79 MW in the last three years, almost the equivalent of adding a new CT.

Several supply expansions have occurred, such as the new Holyrood CT (123 MW), recall power (110 MW) and the new import contract (104 MW). Added capacity assistance has also contributed, and the addition of TL 267 magnified the value of the higher capacity and lower load. Each have proven positive steps that strengthen the position of the IIS in the coming winter, as well as the years leading up to full MF operation. It is nonetheless necessary to test any threats to the supply-demand situation, and substantive, credible threats do indeed exist, primarily in the form of the availability of the LIL and the availability of Hydro's generation fleet.

1. The Status of the LIL

The completion and commercial operation of the LIL was previously considered necessary only when power from MF was ready to flow to the IIS. Fortunately, considerable float existed in the LIL schedule and construction proceeded at a pace that was supportive of a much earlier in-service date. This proved fortuitous when management learned that: (1) added IIS supply was needed, and (2) recall power was available over the LIL.

Nalcor made efforts to assure LIL availability, and hence the recall power, before the winter of 2018-19. Management decided to defer certain work on the LIL's second pole in order to assure maximum attention to getting the first pole in service as soon as possible. While monopole operation has obvious reliability ramifications, the monopole has more than adequate capability to carry the necessary capacity for the 110 MW recall power and the subsequent contracted 104 MW.

Upon direction from the Board, Liberty has been monitoring the "Transition to Operations" (TTO) schedule for the last year. Our primary focus has been on the adequacy of Hydro's preparations to reliably manage the new assets, but we also emphasized LIL progress because of its materiality to Winter 2018-19 supply. In our opinion more attention and pressure from management was necessary to apply to GE, the apparent cause of the primary schedule threats. The serious problems facing GE at the corporate level are well-known, and its capability to meet Nalcor requirements, even with the best of intentions, remains far from clear. We did not see in this quarter signs of significant improvement in the pace of critical work. At an August 17, 2018 meeting with TTO management, the Company representatives did not express confidence in GE's ability to meet an in-service date for the LIL of mid-November.

A presentation from TTO management at that time identified the control software as a primary GE issue, with an important upgrade package presently scheduled for an October 1, 2018 delivery. Allowing for several weeks of installation and testing, and 20-days of continuous, successful LIL operation (as required for acceptance), mid-November completion seemed the best possible outcome. We have considerable skepticism about that date:

- Management did not appear to have confidence that the delivery date would be met
- There was no basis for confidence that the installation would proceed perfectly
- There seemed to be a low probability that the LIL would immediately be able to pass the 20-day run without a trip.

We observed that the 20-day requirement is not typical to begin with - - projects in our experience more typically require a successful 60-day run. This is nonetheless a contract agreement and not subject to change. The much shorter 20-day duration does raise the probability of a successful run, although not necessarily, but equally critical, a long-term reliable system.

We emphasized to TTO management the critical importance of the LIL for this winter. We explained that reliability violations were present with the LIL out of service and that the system would be at elevated risk without the LIL. We suggested that a greater sense of urgency, and a greater level of management attention was necessary. We further indicated that we would recommend enhanced and more frequent Board oversight of Hydro's management regarding the LIL in-service date. GE performance with respect to software delivery and testing, trial and operation, filling of operational positions, and getting any necessary synchronous condensers into service are critical, among the other activities affecting the ability to secure a reliable supply of recall power by December 1, 2018.

We were not able to secure from management information necessary (such as critical path schedule information) for determining the likely impacts of many of these issues. Nalcor's representatives, for example, declared critical path schedule details for GE work on the LIL beyond the scope of legitimate inquiries from us. The limited information we were provided is not sufficient to address the length of likely delays in reliable LIL operation, but we do think they may well prove considerable. That management's lacked confidence in the dates it offered to us on August 17 was demonstrated by Hydro's letter to the Board on August 27 advising of an extension in LIL's completion date to January 2019.

There is no sound basis at present and with the information we do and do not have for considering the new, later date likely. With no basis for identifying a likely date for reliable commercial operation of the first pole, we can nevertheless offer the following interim conclusions:

- We find it unlikely that the LIL (single pole) will be in commercial operation for the start of the winter of 2018-19.

- Acceptance of the facility for operation will not necessarily demonstrate a capability to perform reliably: "Paper" declarations in the industry that critical facilities have been accepted for operation (particularly in other high-pressure situations) are often followed by the emergence of issues that make them undependable for extended periods.

- Whatever the "actual" state of completion and readiness when accepted, we find little likelihood that the LIL will operate reliably in its early months. The LIL will remain prone to the uncertainties any new major facility faces early in its operating life, especially one involving technology new to the operating company. In addition, the current problems with GE are unlikely to simply go away.

  Hydro models the LIL with a forced outage rate of 1 percent. This assumption may be optimistic, given prior reports suggesting multiple monopole trips in the four winter months. The immaturity of the LIL in the coming winter could produce many more outages. Also, the limited duration of the required run (20 days) does little to add confidence that operations after acceptance will be continuous.

2. Generating Assets

Hydro's last three adequacy reports have described growing problems with its generation fleet. The degree of degradation with these assets raises substantial concern.

Deterioration of the thermal assets, including the Holyrood TGS and the Hardwoods and Stephenville CTs, is well known. Management has invested considerably in these facilities. They continue to survive but in a debilitated condition. Hydro intends to address the CT issues directly in the upcoming November 2018 supply analysis - - an analysis that should include the long term plan for the assets and specifically address the remaining lives of Hardwoods and Stephenville.

Holyrood TGS DAFORs		
	12 months ending	
	June 2017	June 2018
Holyrood 1	21.3	32.3
Holyrood 2	19.6	26.6
Holyrood 3	3.3	16.6
All - weighted	15.3	26.2

The Holyrood TGS continues to impose major uncertainty on the supply picture, and that uncertainty has serious implications due to the units' large role in the calculation of LOLH. Hydro previously assumed a DAFOR of 10 percent for each unit, but has elevated that to 15 percent for the base case and added sensitivity cases of 18 and 20 percent. The accompanying table,[1] which shows actual DAFORs, indicates that even the 20 percent sensitivity that was assumed looks low, given the much higher DAFORs actually experienced in the year ending June 2018.

Management has attributed many of Holyrood's 2017-18 problems generally to on-going boiler and air heater fouling, and plans fixes for those problems in the fall of 2018. This generalization understates the poor condition of these units. The frequency of trips and de-rates, the large number of independent events, and the degree of overall degradation are so great that we find it impossible to effectively summarize them here. Rather, we refer to Pages 10-18 of Hydro's quarterly report on unit performance, which we have attached for convenience. The list of contributors to high DAFORs is so long, and the reasons so varied, that it seems impossible to expect any different results this winter. Perhaps the boiler fouling issue will indeed be resolved, like the 2016 boiler tube issues were resolved last year, but the likelihood that such problems will simply be replaced by others, as serious in nature and greater in number, is high.

The condition of the thermal assets comes as no surprise, but the emergence of hydraulic asset problems does. New and expanding penstock issues appear especially troubling. Management reported the root cause of the Bay d'Espoir Penstock 1 in a March 23, 2017 report to the Board, but the current Hydro report states that the 2017 root cause analysis was wrong, requiring investigations to take a new focus.[2] Inspections comprise a key part of Hydro's efforts now, but visual inspections may be proving inadequate. Visual inspection of Penstock 3 in April 2017 showed no evidence of cracking, but non-destructive testing (NDT) a month later confirmed that cracks did indeed exist.[3] The report suggests the need for an aggressive future inspection program, but makes no mention of any new NDT requirements versus visual inspections.

[1] "Quarterly Report on the Performance of Generating Units, For the Quarter ended June 30, 2018", July 30, 2018
[2] NTGA Report, Page 12, Line 29
[3] NTGA Report, Page 13, Line 7

Other hydraulic unit problems continued in 2017, but still await repairs later in 2018. These problems include the rotor key cracking at Upper Salmon, the bearing coolers at Hinds Lake and the Cat Arm spherical valve controls. The report includes no discussion of Exploits, but we note that deliveries under this contract have fallen short of expectations for at least the last three years, resulting in high replacement costs for the lost energy. Hydro has indicated that this issue is neither substantive nor permanent.

The degree to which such hydraulic issues suggest deteriorating assets remains unclear. Hydro should be asked to provide more information on the matter. In any event, we believe that the Board should be concerned about the number of issues and the length of time during which they continue as unresolved.

The overall deteriorating condition of the fleet demands action by Hydro management. We have included such a recommendation later in this report. In the meantime, the major threat for this winter is the Holyrood TGS. That threat could produce very severe consequences on days when the LIL is unavailable.

3. The Maritime Link

Addition of the ML to the Lower Churchill Project has been recognized as producing operating benefits on many levels. With the ML now in service, those benefits are materializing, including imported energy to displace Holyrood generation and mitigation of UFLS. However, Hydro has excluded this potentially major supply asset and primary boost to reliability from its supply analysis. Hydro states that, "while access to markets via the Maritime Link also bolsters system reliability, it has not been included in this analysis given the conservative focus of this report".[4] Management further states in PUB-NLH-002 on Hydro's May, 2018 Near-term Generation Adequacy Report that, "Hydro believes that including the Maritime Link energy and capacity at this time in the analysis would be an optimistic view of provision of supply."

The ML is indeed producing substantial benefits in the forms of: (1) economy energy that displaces more expensive energy from Holyrood TGS and the CTs, and (2) the fast response of the frequency controller, which has already prevented multiple instances of under-frequency load shedding. However, access to firm capacity represents a notable missing benefit. We believe that this benefit is becoming less practical because of commercial and operational issues, and firm capacity post-MF may not be practical at all, because the time lag to bring capacity into Newfoundland, even if it were available, will preclude its qualification as spinning (10 minute) or operating (30 minute) reserves.

Not to diminish the current and likely long term benefits of the ML, it will not, however, prove the source of long-term, firm capacity that some had hoped.

4. The No-LIL Scenario

Hydro's analysis specifically included a case postulating a one-year LIL delay, followed by operation at only 50 percent capacity thereafter. Our focus on this coming winter in this report

[4] NTGA report, Page 1, Line 11

makes only the first year pertinent. It provides an indicator of the consequences of the LIL being unavailable at any time.

	Conservative Supply Case	Contracted Supply Case	No LIL
IIS Forecast Peak Demand	1,789	1,789	1,789
Capacity at Peak	2,101	2,205	1,991
Plus Available Capacity Assistance (100 MW)	2,201	2,305	2,091
Reserve Margin (MW)	412	516	302
Reserve Margin (%)	23.0%	28.8%	16.9%

Loss of the LIL has an especially precipitous effect on reserve margins, reducing them to about 300 MW and (16.9 percent). One might ordinarily find such resulting margins acceptable for the coming winter, but not when considering a Holyrood with 20-30 percent DAFORs. LOLH rises to 6.19 (well above the criterion of 2.8) when assuming a Holyrood DAFOR of 20 percent. EUE also rises to 385, or more than double the criterion. This not a desirable situation.

A major loss of load event in this scenario requires a combination of circumstances: (1) LIL out of service, (2) loss of multiple Holyrood units and (3) a high load day. The first condition is very likely, at least for the first part of the winter. The second is increasingly more likely, given Holyrood's reliability issues. This all suggests that, for at least part of this winter, the IIS may be at the mercy of the weather.

E. Recommendations

1. **The Board should direct Hydro to implement an enhanced monitoring program of Nalcor's activities required to place the LIL reliably in service.**

This monitoring effort should begin with a review of the detailed critical path schedule of all activities required to reach commercial operation of the LIL, including but not limited to the GE software work, installation and testing of software, successful initial operations to permit acceptance, acquisition, training and development of operating and support personnel, and installation of any necessary synchronous condensers. Hydro should report to the Board, no later than October 1, 2018, with updates every two weeks thereafter. Updates should include continuing analysis of the expected completion date.

2. **The Board should require Hydro to provide all requested schedule information regarding potential supply issues, including details associated with the drivers of TTO constraints regarding the LIL.**

The current organizational structure of Hydro and Nalcor places responsibility for the construction of the LIL in Nalcor but makes Hydro the entity dependent on LIL entering reliable service as a component of supply for customers. We have observed transparency and accountability concerns in connection with this distinction. TTO's position on not providing certain schedule information has significant implications for the Board's visibility on activities critical to Hydro's management of its supply risks. MF and the LIL will soon become electric system assets of paramount importance for the IIS - - as primary determinants of electric system reliability for many decades.

A lack of transparency regarding how likely delays on critical assets may be substantially encumbers the Board's ability to assess what Hydro needs to do and when to manage supply risks.

3. **The Board should direct Hydro to develop contingency plans to mitigate the consequences associated with the eventuality that the LIL will not be available, or will be significantly unreliable, for all or part of the coming winter.**

The opportunity to add new capacity for this winter does not exist, apart from limited opportunities for additional capacity assistance. In addition, some ML-related options may exist. In any event, Hydro should plan to mitigate the consequences of any capacity shortfall, including steps to seek demand reduction and reduce equipment downtime. To the extent practical, the LIL should be operated and loaded with due consideration to mitigate the consequences of a trip.

4. **The Board should direct Hydro to provide a specific plan to improve its program and its organizational capabilities in asset management as applicable to the generation fleet.**

The condition of the fleet, the widespread nature of asset issues, and the seeming inability to resolve the issues promptly, question whether Hydro's asset management efforts, at least as applied to the generation assets, are effective. In our Phase 2 report (August 19, 2016) we wrote:[5]

> *Under ordinary circumstances, the failures of old machines might be expected as they are not worth a lot of new investment and one must work hard and hope for the best to hold them together. But this is not the case here. Quite the contrary, the analysis of the equipment has been done and the specific actions to extend their lives and assure reliability have been made over a period of many years. Yet the Holyrood units demonstrated themselves to be extremely vulnerable and the CTs are likely to continue the pattern of something significant seeming always to go wrong.*
>
> *The conclusion that changes are necessary in Hydro's approach to power plant asset management is unescapable. The failures in the management of the thermal units are extreme and are likely to have adverse consequences for a long time.*

As a result of this conclusion, we recommended:[6]

> *Recommendation VI-7. Hydro should (a) define the new skills and capabilities required by the organization; (b) define the improvements needed in skills and capabilities in operations, planning, reliability engineering and **asset management**; (c) develop new, high standards for technical and managerial positions in those areas; (d) define gaps between future needs and current skills and capabilities; and (e) acquire the required skills and capabilities through a combination of internal development and external hiring.* [Emphasis added]

Two years later, our conclusion and recommendation remain appropriate. In fact, further deterioration at Holyrood and problems now involving the hydraulic units as well may demonstrate problem growth, not mitigation. We do not mean to suggest that Hydro has done nothing; there have been actions, many documented in Hydro's "Establishing a Robust Operational Philosophy and Enhancing Skills and Capabilities Relating to System Reliability and Analysis", March 30,

[5] Page 98 of the Phase 2 report
[6] Phase 2 report, Page 114

2017. It is not clear, however, what specific organizational actions have been taken to provide improved skills and capabilities in asset management.

5. **The Board should direct Hydro to provide some context and long-term implications for its analysis of the problems at the hydraulic units, as described in the latest Near-Term Generation Adequacy Report.**

Hydro's analysis is detailed, but the degree of the problem it describes is not clear. Some context as to how the new problems are typical or atypical of similar industry units and the implications regarding the long-term adequacy of the hydraulic fleet would be helpful.

Quarterly Report on Performance of Generating Units

For the Quarter ended June 30, 2018

July 30, 2018

A Report to the Board of Commissioners of Public Utilities

newfoundland labrador hydro
a nalcor energy company

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1.0 Introduction

In this report, Newfoundland and Labrador Hydro (Hydro) provides data on forced outage rates of its generating facilities. This data is provided in relation to historical forced outage rates and assumptions used for system planning purposes.

The forced outage rates are provided for the 12-month periods of July 1, 2017 to June 30, 2018 and July 1, 2016 to June 30, 2017 and reflect the generating units associated with:

- hydraulic generation facilities;
- Holyrood Thermal Generating Station; and
- gas turbines.

Reporting on the prior 12-month period is included for comparison purposes. Additionally, total asset class data is presented on an annual basis for the years 2006-2016. This report provides data on outage rates for forced outages, not planned outages.

The forced outage rates of Hydro's generating units are presented using three measures:

1. Derated Adjusted Forced Outage Rate (DAFOR) for the hydraulic and thermal units;
2. Utilization Forced Outage Probability (UFOP) for the gas turbines; and
3. Derated Adjusted Utilization Forced Outage Probability (DAUFOP) for the gas turbines.

DAFOR is a metric that measures the percentage of the time that a unit or group of units is unable to generate at its maximum continuous rating due to forced outages. The DAFOR for each unit is weighted to reflect differences in generating unit sizes to provide a company total and reflect the relative impact a unit's performance has on overall generating performance. This measure is applied to hydraulic and thermal units. This measure is not applicable to gas turbines due to their operation as standby units and relatively low operating hours.

UFOP is a metric that measures the percentage of time that a unit or group of units will encounter a forced outage and not be available when required. This metric is used for the gas turbines.

DAUFOP is also a metric that measures the percentage of time that a unit or group of units will encounter a forced outage and not be available when required, but also includes impact of unit deratings. This metric is used for the gas turbines.

The forced outage rates include outages that remove a unit from service completely, as well as instances when units are derated. If a unit's output is reduced by more than 2%, the unit is considered derated by Canadian Electricity Association (CEA) guidelines. Per CEA guidelines, to take into account the derated levels of a generating unit, the operating time at the derated level is converted into an equivalent outage time.

In addition to forced outage rates, this report provides outage details for those outages that contributed materially to forced outage rates exceeding those used in Hydro's generation planning analysis for both the short and long term.

2.0 Period Ending June 30, 2018 Overview

Table 1: DAFOR, UFOP, and DAUFOP Overview (%)

Class of Units	July 1, 2016 to June 30, 2017	July 1, 2017 to June 30, 2018	Base Planning Assumption[1]	Near-Term Planning Assumption[2]
Hydraulic (DAFOR)	4.85	2.04	0.90	2.60
Thermal (DAFOR)	15.27	26.22	9.64	14.00
Gas Turbine (Combined) (UFOP)	8.68	6.78	10.62	20.00
Gas Turbine (Holyrood) (UFOP)	2.46	0.06	5.00	5.00
Gas Turbine (Combined) (DAUFOP)	8.68	24.11	-	30.00
Gas Turbine (Holyrood) (DAUFOP)	2.46	0.06	-	5.00

There was an improvement in hydraulic DAFOR and a decline in thermal DAFOR performance for the current 12-month period ending June 2018, compared to the previous 12-month period ending June 2017 (Table 1). The combined[3] gas turbine UFOP performance shows an improvement in performance for the current period compared to the previous period, while DAUFOP shows a decline in performance.

[1] Hydro is reviewing all base planning assumptions as part of its reliability criteria and supply adequacy assessment, to be submitted to the Board in November 2018.

[2] Near-term Generation Adequacy Report, November 15, 2017, refer to section 5.0 for further details.

[3] Combined Gas Turbines include the Hardwoods, Happy Valley, and Stephenville units. The performance of the Holyrood Gas Turbine was not included in the combined base planning or sensitivity numbers as these numbers were set prior to the Holyrood Gas Turbine's in service date.

In the 10-year period prior to 2015, the hydraulic units showed a somewhat consistent DAFOR. The DAFOR of the current 12-month period compared to the previous 10 years is higher, primarily due to penstock issues experienced on Units 1 and 2 at Bay d'Espoir in 2016 and 2017.

For the Holyrood thermal units, the forced outage rate of the current period ending June 2018 is 26.22%, which is above the base planning assumption of 9.64%, the sensitivity of 11.64%, and above the near-term planning assumption of 14.00%[4]. This is primarily caused by an airflow derating on Unit 1 and Unit 2 that continued in 2017 and 2018 and an extended forced outage on Unit 1 in February 2018.

The current Holyrood period DAFOR is not an indicator of what to expect for the coming winter season due to the work being completed to improve the unit's performance for airflow limitations. With an interest in shortening Holyrood generating hours (operating time) to avail of more economic purchased electricity, there will be less operating hours in the upcoming fall. The lower operating hours has the effect of negatively impacting the DAFOR calculation as compared to having the units on.

Hydro's combined gas turbines' UFOP in the 10-year period prior to 2015 was generally consistent at approximately 10% until the year 2012 when the rate exceeded 50%. Since 2012, the UFOP has been improving each year. For the current 12-month period ending June 30, 2018, performance was affected by forced outages to the Hardwoods, Happy Valley, and Stephenville units.

Note that the data for 2006 to 2016 in Figure 1, Figure 2, and Figure 3 are annual numbers (January 1 to December 31), while the data for 2017 and 2018 are 12-month rolling numbers (July 1 to June 30 for each year).

[4] While the near-term planning assumption for thermal was materially exceeded in the preceding 12-month period, there were no supply issues experienced. Improved performance at the other assets contributed to this outcome. Further, the near-term planning assumption is a probabilistic view of system performance under various criteria.

3.0 Generation Planning Assumptions

The DAFOR and UFOP indicators used in Hydro's generation planning model are representative of a historic average of the actual performance of these units. These numbers are noted in Table 2 under the column "Base Planning Assumption". This is a long-term outlook. The Base Planning Assumptions are under review as part of the 2018 reliability review work ongoing and this review is being reported to the Board as part of Phase 2 of the Outage Inquiry.

Hydro also provides a sensitivity number for DAFOR and UFOP as part of its generation planning analysis. This number takes into account a higher level of unavailability, should it occur, to assess the impact of higher unavailability of these units on overall generation requirements. During the 12-month period ending June 30, 2018, the gas turbine units performed well within this sensitivity range for UFOP, while both the hydraulic and thermal classes performed outside of the sensitivity range for DAFOR.

The Holyrood gas turbine has a lower expected rate of unavailability than the original gas turbines (5% compared to 10.62%) due to the fact that the unit is considered relatively new and can be expected to have better availability than the older units.[5]

Hydro's generation long-term planning assumptions for DAFOR and UFOP for the year 2018 are noted in Table 2.

Table 2: DAFOR and UFOP Long-Term Planning Assumptions

	DAFOR (%)		UFOP (%)	
	Base Planning Assumption	**Sensitivity**	**Base Planning Assumption**	**Sensitivity**
Hydraulic Units	0.90	0.90		
Thermal Units	9.64	11.64		
Gas Turbines - Existing			10.62	20.62
Gas Turbines - New			5.0	10.0

[5] Hydro selected a 5% UFOP for the new Holyrood GT following commentary on forced outage rates contained in the *Independent Supply Decision Review – Navigant (September 14, 2011).*

As part of Hydro's analysis of energy supply up to Muskrat Falls interconnection, Hydro completes comprehensive reviews of, and produces reports on, energy supply for the Island Interconnected System. The Near-Term Generation Adequacy report, filed on November 15, 2017, contains analysis based on the near-term DAFOR and DAUFOP and the resulting implication for meeting reliability criteria until the interconnection with the North American grid. In the November report, Hydro used the DAUFOP metric as the measure of gas turbine unit reliability into the near term. In 2018, Hydro will be measuring and reporting using DAUFOP and UFOP for the gas turbines.

The DAFOR and DAUFOP assumptions used in developing Hydro's November 2017 Near-term Generation Adequacy report are noted in Table 3.

Table 3: DAFOR AND DAUFOP Near-Term Generation Adequacy Analysis Assumptions

	DAFOR (%) **Near-Term Generation Adequacy Assumption**	**DAUFOP (%)** **Near-Term Generation Adequacy Assumption**
All Hydraulic Units	2.6	
Bay d'Espoir Hydraulic Units	3.9	
Other Hydraulic Units	0.7	
Holyrood Plant	14.0	
Holyrood Unit 1	15.0	
Holyrood Unit 2	10.0	
Holyrood Unit 3	18.0	
Hardwoods and Stephenville Gas Turbines		30.0
Holyrood Gas Turbine		5.0

4.0 Hydraulic Unit Forced Outage Rate Performance

The hydraulic unit forced outage rates are measured using the CEA metric, DAFOR. Detailed results for the 12-month period ending June 30, 2018, are presented in Table 4, as well as the data for the 12-month period ending June 30, 2017. These are compared to Hydro's short term generation adequacy assumptions, as used in the Near-term Generation Adequacy report, and Hydro's long-term generation planning assumptions for the forced outage rate.

Table 4: Hydraulic Weighted DAFOR

Generating Unit	Maximum Continuous Unit Rating (MW)	12 months ending June 2017 (%)	12 months ending June 2018 (%)	Hydro Generation Base Planning Assumption (%)	Near-Term Planning Assumption (%)
All Hydraulic Units - weighted	954.4	4.85	2.04	0.90	2.60
Hydraulic Units					
Bay D'Espoir 1	76.5	23.04	8.67	0.90	3.90
Bay D'Espoir 2	76.5	26.75	12.41	0.90	3.90
Bay D'Espoir 3	76.5	0.02	0.01	0.90	3.90
Bay D'Espoir 4	76.5	0.97	0.15	0.90	3.90
Bay D'Espoir 5	76.5	0.00	0.00	0.90	3.90
Bay D'Espoir 6	76.5	1.30	0.21	0.90	3.90
Bay D'Espoir 7	154.4	0.00	1.80	0.90	3.90
Cat Arm 1	67	1.02	0.22	0.90	0.70
Cat Arm 2	67	0.00	0.09	0.90	0.70
Hinds Lake	75	1.14	0.02	0.90	0.70
Upper Salmon	84	0.86	0.16	0.90	0.70
Granite Canal	40	1.15	0.15	0.90	0.70
Paradise River	8	7.58	0.69	0.90	0.70

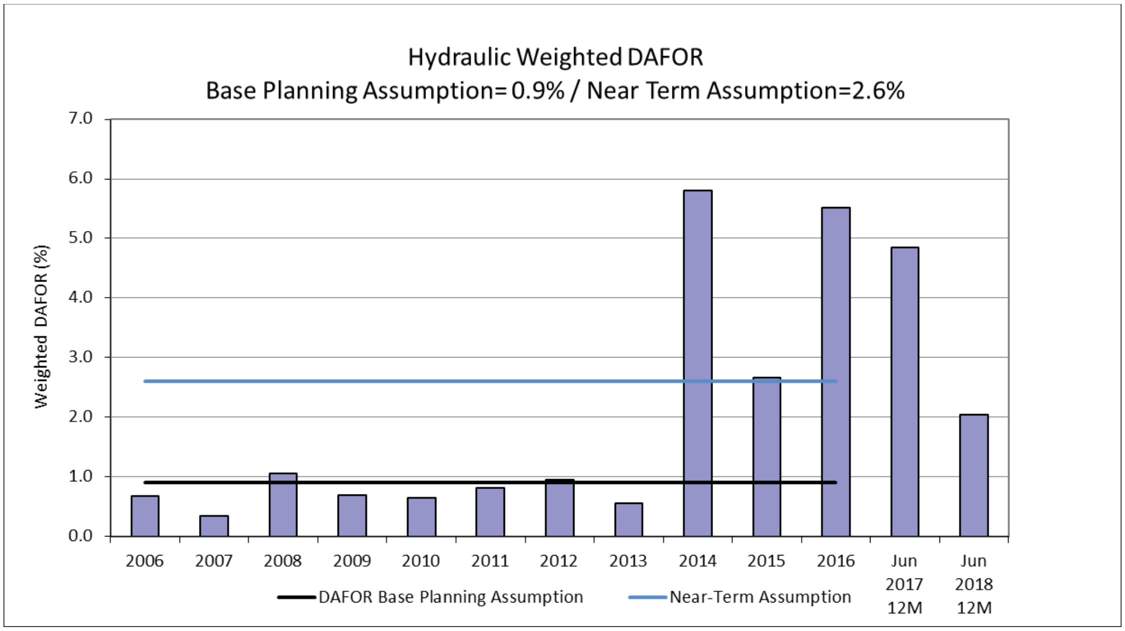

Figure 1: Hydraulic Weighted DAFOR

Considering the individual units' performance, the assumed Hydro generation base planning DAFOR was materially exceeded for Bay d'Espoir Unit 1 and Bay d'Espoir Unit 2. Also, there were exceedances compared to base planning assumption for Bay d'Espoir Unit 7 for the current period.

The Bay d'Espoir Unit 1 DAFOR of 8.67% and Unit 2 DAFOR of 12.41%, exceeded the base planning assumption of 0.9% and the near-term assumption of 3.9% for an individual Bay d'Espoir unit. This was due to Units 1 and 2 being removed from service on November 4, 2017 as a result of a leak in Penstock 1, which provides water to both units. A consultant was engaged in the process to provide engineering analysis and recommendations to return the penstock to reliable service. Extensive inspection and testing was completed, which resulted in the damaged section being replaced. All additional suspect areas were also cleaned and refurbished and additional backfill was placed over a section of the ruptured area as this had been part of the approved capital plan resulting from the 2016 leak. Findings from the final root cause report are being implemented and the Board approved Condition Assessment work[6] is currently underway. The penstock was returned to service on December 8, 2017.

The Bay d'Espoir Unit 7 DAFOR of 1.80% exceeded the base planning assumption of 0.9% and is less than the near-term assumption of 3.9% for an individual Bay d'Espoir unit, as a result of the unit being unavailable from July 3, 2017, to July 9, 2017, due to a failure in the collector assembly. An investigation was completed, and it was determined that there was a flash over between the slip rings, which was caused by excessive brush wear. As a result of the investigation, improvements to the preventive maintenance (PM) program have been implemented across the hydraulic generation fleet of assets. As a result of this event, all brush gear assemblies had an additional inspection completed prior to December 1, 2017 and no issues were found.

5.0 Thermal Unit Forced Outage Rate Performance

The thermal unit forced outage rates are measured using the CEA metric, DAFOR. Detailed results for the 12-month period ending June 30, 2018, are presented in Table 5, as well as the data for the 12-month period ending June 30, 2017. These are compared to Hydro's short-term generation adequacy assumptions, as used in the Near-term Generation Adequacy report, and Hydro's long-term generation planning assumptions for the forced outage rate.

Table 5: Thermal DAFOR

Generating Unit	Maximum Continuous Unit Rating (MW)	12 months ending June 2017 (%)	12 months ending June 2018 (%)	Hydro Generation Base Planning Assumption (%)	Near-Term Planning Assumption (%)
All Thermal Units - weighted	490	15.27	26.22	9.64	14.00
Thermal Units					
Holyrood 1	170	21.33	32.30	9.64	15.00
Holyrood 2	170	19.57	26.62	9.64	10.00
Holyrood 3	150	3.29	16.60	9.64	18.00

[6] P.U. 23(2018).

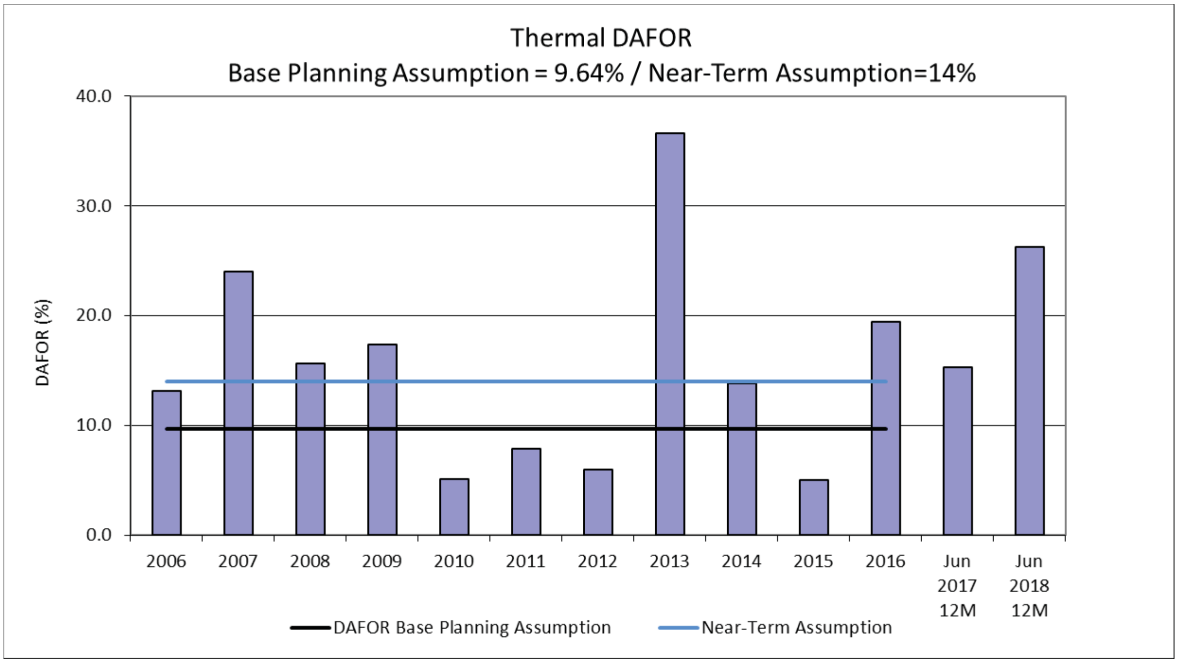

Figure 2: Thermal DAFOR

For the 12-month period ending June 31, 2018, the weighted DAFOR of 26.22% for all thermal units is above the assumed Hydro generation base planning DAFOR value of 9.64%, and the near-term assumption of 14.00%.[7] Unit 1 DAFOR was 32.30% and Unit 2 DAFOR was 26.62%. The performance for both Units 1 and 2 was above the base planning assumption of 9.64% and the near-term assumption of 15% (Unit 1) and 10% (Unit 2). Unit 3 DAFOR was 16.60%, which is above the base planning assumption of 9.64% but below the near-term assumption of 18.0%.

The DAFOR performance for Holyrood Unit 1 (170 MW) was affected by the following events in the current 12 month to-date period:

- The 2017 maintenance outage on Unit 1 was from July 5, 2017 until September 11, 2017. The unit was put on-line on September 17, 2017 to allow for on-line commissioning of the new exciter controls system by the original equipment manufacturer, ABB. The unit tripped at 70 MW on September 18, 2017 during commissioning of the new exciter controls on that unit. The unit was de-rated to 50 MW

[7] See Hydro's Near-term Generation Adequacy Report, November 15, 2017, section 7.0 for results discussing Holyrood plant DAFOR at 15% compared to 14%. Plant DAFOR of 15% does result in minor differences only, and these differences result only in the extreme sensitivity cases, not the expected system operating cases.

(below under frequency load shedding limits) until September 21, 2017, when the cause of the trip was determined. This was to ensure that any further trips would not impact customers. An investigation determined that this trip, which happened when starting a boiler feed pump, was due to low unit board voltages. Starting the pump caused the already low voltage to drop below acceptable levels and this appropriately engaged under voltage protection and a unit trip. Voltages had been reduced intentionally as part of the exciter commissioning and were not returned to normal levels prior to starting the pump. This issue has been addressed with commissioning activities to ensure that it will not reoccur.

- Unit 1 tripped on October 5, 2017 and was de-rated to a precautionary load of 35 MW, while the reason for the trip was being investigated and corrected. It was determined that the trip was caused by frayed wires in one of the forced draft fan motors and, following repairs, the unit was returned to full capability on October 10, 2017.
- From October 17, 2017 to October 22, 2017, the Unit was de-rated to 154 MW due to low steam pressure while waiting for safety valve testing to be completed. The safety valve testing was completed on October 24, 2017, but the Unit was further de-rated to 145 MW from October 22, 2017 to October 24, 2017 and to 135 MW until the end of the month due to overheating motor windings in the west forced draft fan. Plans were established to replace this motor after completion of Unit 2 exciter commissioning. The spare motor was brought to site and the winding temperature was monitored regularly for changes. The spare motor was installed during an outage from November 7, 2017 to November 11, 2017. The Unit was returned to service on November 12, 2017 but remained de-rated to 145 MW due to high furnace pressure.
- On November 14, 2017 the Unit was taken off-line to repair a piping leak at the condenser flash tank. This was repaired and the Unit returned to service on November 15, 2017. However another leak developed in the area and the Unit was removed from service on November 15, 2017 for 12 hours for repair.
- Unit 1 remained limited to 145 MW until it was taken off-line on November 30, 2017 to perform an air heater wash and additional maintenance. The Unit was returned to

service on December 4, 2017, after completion of a maintenance outage to perform an air heater wash and additional maintenance work to restore capacity. This included a pressure wash of the top air heater baskets. A load test completed on December 5, 2017 confirmed a capacity of 150 MW[8] with the unit load limited by high furnace pressure.

- On January 3, 2018 the Unit capability was reduced from 150 to 135 MW as a result of oscillations in the turbine control valve hydraulic ram. An outage was taken from January 5 to 6 replace a loose control cable on the hydraulic ram and to complete an air heater wash. After this work the load was restored to 145 MW, limited by high furnace pressure, and it was noted that the control valve oscillations had not been eliminated. On January 18, 2018 the oscillations had increased and the load was reduced to 140 MW as a result. On January 20, 2018 the Unit was taken off-line to replace another control cable as recommended by GE to resolve the oscillation issue. While the Unit was off-line for this work the boiler stop valve failed, which resulted in an extension to the outage. The Unit remained off-line until February 2, 2018 while stop valve refurbishment was ongoing. During this time, the hydraulic ram was removed from the turbine and sent off-site for refurbishment to ensure that the oscillation problem had been resolved. Also, a high pressure wash was completed on the air heater baskets to 12,500 psi.
- The outage due to the boiler stop valve failure extended from January 20, 2018 until February 21, 2018, following several solutions which attempted to address the leak. On February 21, 2018 the stop valve work was complete and the unit was returned to service.
- On February 22, 2018 the Unit had to be taken off-line due to a turbine bearing issue. Lube oil had leaked, undetected, from the bearing during the stop valve outage. This led to a smoldering underneath the bearing when the components heated. The

[8] Hydro continues to work towards restoring full load on all three units. Hydro set up an engineering team to work with the boiler service provider and other industry experts. This team has recommended replacement of air heater baskets on all three units, correction of excessive air heater leakage on Unit 3, cleaning of economizers on Unit 1 and Unit 2, and use of fuel additive on all three units to prevent continued fouling. These recommendations address the issues of high furnace pressure in Unit 1 and Unit 2 and the issues of high air heater fouling and air flow limitations on Unit 3. They are currently being pursued with the intent to complete this work during the 2018 annual overhauls.

contaminated insulation was replaced and an inspection of the bearing confirmed no active leak. The Unit was returned to service on February 25, 2018.

- On February 28, 2018 a load test was completed to 148 MW, with load limited by high furnace pressure due to boiler and air heater fouling. By the end of March 2018 the Unit's capability had reduced to 137 MW as a result of continued fouling in the boiler and air heaters.
- There were two unit trips related to forced draft fan variable frequency draft trips. These occurred on March 19, 2018 and March 26, 2018. In both instances the Unit was returned to service using replacement parts from inventory. During the outage related to the March 19, 2018 trip, a problem with the Mark V turbine governor system was also resolved. Hydro is continuing to work towards resolving the problems with variable frequency drive reliability.
- On April 12, 2018 the load was reduced to 126 MW, limited by high furnace pressure as a result of continued boiler and air heater fouling. The capability of the unit continued to decline for the same reason. On May 6, 2018 the unit capability was 122 MW and on May 15, 2018 it was 116 MW.
- On May 21, 2018 the unit tripped at 70 MW on high boiler drum level. The cause was suspected to be a trip of the east boiler feed pump, which caused unstable water level in the drum and led to the trip. The unit was returned to service later that same day with only the west boiler feed pump in service and the load restricted temporarily to 70 MW until the health of the east pump was verified. The Unit was returned to 116 MW on May 21, 2018 once the health of the east pump was verified. The pump was ruled out as the cause of the trip, and the cause was determined to be a failure of a turbine control valve stem. There is a scheduled turbine valve outage in 2018 and the contractor will replace the stem as part of this project.
- On June 4, 2018 the Unit was further de-rated to 100 MW, limited by high furnace pressure as a result of on-going boiler and air heater fouling. By the end of June this had further reduced to 88 MW.

- On June 16, 2018, while on a brief planned outage to change worn generator brushes, a pressure gauge failed on the fuel oil system resulting in a spill that had to be cleaned up before the Unit could be safely returned to service. On June 17, 2018 while starting up the unit, a bearing failed on the east forced draft fan and required replacement. The Unit was returned to service on June 18, 2018; however, the same bearing failed after a few hours of operation. The bearing was again replaced and the Unit was successfully returned to service on June 19, 2018. Hydro has made arrangements for a field representative from the fan original equipment manufacturer to assist with the failure analysis once the Unit is removed from service for the annual outage.

The DAFOR performance for Holyrood Unit 2 (170 MW) was primarily affected by the following events:

- Unit 2 was removed from service at the end of July 2017 to accommodate the planned total plant outage and the Unit annual maintenance outage. During the Unit outage, additional work was completed to address air flow issues. This included additional boiler cleaning and air heater upgrades.
- The Unit returned from the annual planned outage and was placed on-line for commissioning of new exciter controls on October 28, 2017 with a scheduled de-rating of 35 MW. Exciter commissioning was interrupted by two forced outages. From October 28, 2017 to October 30, 2017 the Unit was taken off-line due to a combustion upset in the boiler. The Unit was returned to service with load restricted to 50 MW. It was determined that the upset was due to the incomplete set-up of a new fuel flow transmitter. Set-up of the transmitter was completed on November 2, 2017. Also, from October 30, 2017 to November 1, 2017 the Unit was removed from service to replace oil-soaked turbine insulation that resulted from an oil leak at a turbine bearing.
- From November 3, 2017 until November 4, 2017, the Unit was de-rated to 70 MW and subsequently to 110 MW while completing commissioning of the new exciter controls. From November 4, 2017 to November 8, 2017, the Unit was de-rated to 150 MW while waiting for safety valve testing to be completed. From November 8, 2017 to November

20, 2017, the Unit was de-rated to 165 MW until a leaking safety valve could be restored. To complete this work an outage was required. The Unit was taken off-line on November 20, 2017 and returned to service on November 24, 2017. An air heater wash was also completed during this outage. A load test on November 28, 2017 revealed that the Unit was capable of 160 MW, limited by high furnace pressure.

- On December 19, 2017, the Unit experienced a 14-hour deration to 70 MW as a result of a trip of one forced draft fan on the unit. The cause of the fan trip was corrected and the fan returned to service later that day in time for the evening peak, with the unit again capable of 160 MW.
- The capability of the Unit continued to decline due to ongoing fouling during operation. On January 4, 2018, the capability had reduced to 154 MW. On January 25, 2018, the capability had reduced to 135 MW due to high furnace pressure as a result of boiler and air heater fouling. On February 14, 2018, the capability had reduced to 117 MW. At the end of February the capability had reduced to 100 MW. System requirements, given the issues with Unit 1, had precluded an air heater wash on this Unit during the month of February 2018. An air heater wash was completed from March 5, 2018 to March 6, 2018; however, this was not successful in restoring any load. By the end of March 2018, the Unit capability had reduced to 90 MW as a result of continued boiler and air heater fouling during operation.
- On February 7, 2018, the Unit was taken offline for a short, planned outage to replace generator brushes. There was a forced extension to this outage when a unit board breaker tripped during restart of the Unit. Electricians were called in to reset the breaker.
- The Unit was further de-rated to 70 MW from March 1, 2018 to March 2, 2018 due to an issue with the west boiler feed pump. A water leak from a reference line nearby caused contamination of the pump lube oil and the pump was taken off-line until the repairs were completed.
- On March 22, 2018, one of the turbine reheat intercept valves became stuck during regular on-line testing and the Unit had to be taken off-line for approximately eight

hours to replace the valve servos. Hydraulic fluid contamination will be addressed during the annual outage to prevent recurrence.

- At the beginning of April 2018 the unit was rated at 80 MW due to high furnace pressure as a result of boiler and air heater fouling. This capability further reduced to 70 MW on April 24, 2018 and remained at this level until the unit was taken off line for the annual outage.
- On April 3, 2018 the unit was taken offline on a forced outage to repair a leak in the turbine control valve hydraulic ram. The ram was rebuilt and the unit returned to service on April 4, 2018; however, once installed the seals required additional adjustment. The Unit was returned to service April 5, 2018. Return to service after this outage was delayed by approximately eight hours on April 5, 2018 due to an issue in the switchyard with the B2B11 breaker. TRO is replacing this breaker during the 2018 annual outage.
- Unit 2 was available but not operating from April 26, 2018 to May 18, 2018 with the available load de-rated to 70 MW due to high furnace pressure as a result of boiler and air heater fouling. During this time the Unit was kept in hot standby, maintaining an eight hour return to service time if recalled. On May 18, 2018 the Unit was taken offline to address a suspected stress failure of a tube in the lower waterwall (not in the area of previous boiler tube thinning failure issues). The two failed tubes will be sent to an independent lab to determine the failure cause and any recommended mitigation, to be implemented during the annual maintenance outage. At the time of the failure, it was determined that the Unit was no longer required for system reliability requirements and could be placed on planned outage in preparation for the annual outage. The tube leak will be corrected during the annual outage.

The DAFOR performance for Holyrood Unit 3 (150 MW) was primarily affected by the following events:

- On December 13, 2017, Unit 3 was de-rated to 135 MW as a result of air flow issues. The unit capability declined steadily to 105 MW until an air heater wash could be completed on December 31. The wash was successful in restoring the load to 131 MW. The available load continued to decline due to ongoing air heater fouling. On January 18 the available load was determined to be 120 MW and on February 10, this had further reduced to 100 MW. An air heater wash outage was completed from February 10 - 11, 2018. System requirements, with Unit 1 already off-line, had precluded an air heater wash on this unit until that time. When the Unit was returned to service there was a de-rating to 70 MW for approximately 10 hours when the west boiler feed pump failed to start.
- This was resolved and the available load was determined to be 110 MW, still limited by air heater fouling. The Unit was capable of 100 MW at the beginning of March 2018. This capability had further reduced to 75 MW on March 20, 2018. An air heater wash outage was completed on March 28, 2018 and the predicted load after this wash was 110 MW. This Unit was not required for the system and was left on standby until the planned unit outage in early April 2018. On June 1, 2018 the Unit 3 generator was put in service in synchronous condenser mode.
- On January 11, 2018, a ¾” diameter domestic water pipe located above the Unit 3 exciter ruptured at a cap and the resulting water leak contacted the exciter causing a Unit trip. There was no significant equipment damage resulting from this incident and once the exciter was safely dried, the Unit was returned to service on January 12, 2018. This event was investigated and the leak repaired. A shut off valve was relocated for improved access in the event of a further trip, regular inspections of the area were implemented, and a plan was formulated to replace this piping during the annual outages. On February 14, 2018, the Unit load was reduced to 50 MW for approximately eight hours as a precautionary measure due to another leak in a domestic water line in

close proximity to the exciter. After this event, the piping was relocated so that further leaks would not impact the exciter.

6.0 Gas Turbine UFOP Performance

The combined UFOP for the Hardwoods, Happy Valley and Stephenville gas turbines was 6.78% for the 12-month period ending June 30, 2018 (refer to Table 6). This is below the base planning assumption of 10.62% and the near-term assumption of 20.00%. The current period UFOP is lower than the previous period UFOP of 12.32%. For the current period, the Hardwoods UFOP is 1.35% and the Stephenville UFOP 4.62%, both of which are better than the base planning assumption of 10.62%. Happy Valley's UFOP is 19.27% for the current period compared to 0.00% in the previous period.

Table 6: Gas Turbine UFOP

Gas Turbine Units	Maximum Continuous Unit Rating (MW)	12 months ending June 2017 (%)	12 months ending June 2018 (%)	Hydro Generation Base Planning Assumption (%)	Near-Term Planning Assumption (%)
Combined Gas Turbines	125	8.68	6.78	10.62	20.00
Stephenville	50	13.10	4.62	10.62	20.00
Hardwoods	50	10.14	1.35	10.62	20.00
Happy Valley	25	0.00	19.27	10.62	20.00

The Holyrood (HRD) GT UFOP of 0.06% for the current period is better than the base planning and near-term assumptions of 5.00% (refer to Table 7).

Table 7: Holyrood GT UFOP

Gas Turbine Units	Maximum Continuous Unit Rating (MW)	12 months ending June 2017 (%)	12 months ending June 2018 (%)	Hydro Generation Base Planning Assumption (%)	Near-Term Planning Assumption (%)
Holyrood GT	123.5	2.46	0.06	5.00	5.00

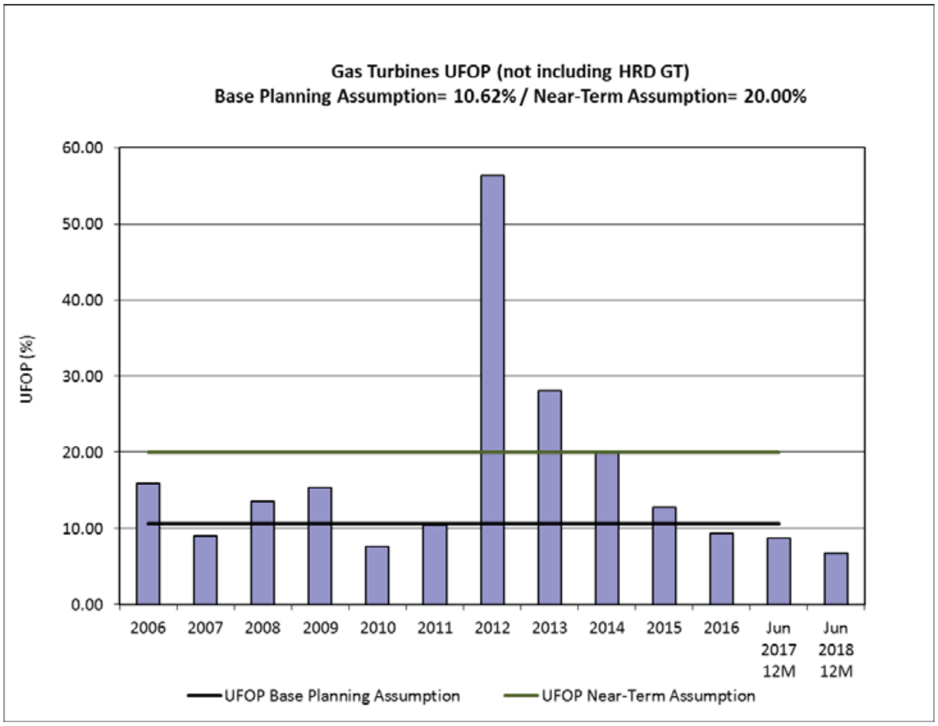

Figure 3: Gas Turbine UFOP – HWD/HVY/SVL Units

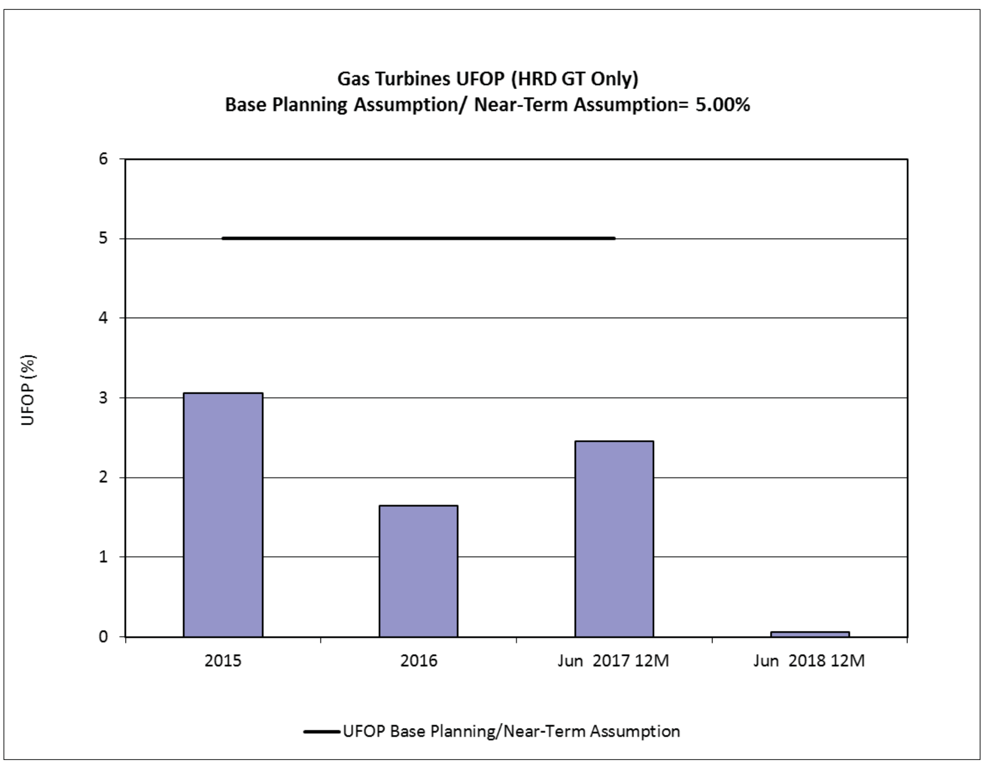

Figure 4: Gas Turbine UFOP – HRD Unit

On September 16, 2017, the Happy Valley gas turbine tripped when attempting a black start of the unit to support an unplanned outage in the Happy Valley area. Hydro's investigation found that the cause of the trip was related to the operation of a voltage protection relay in the terminal station. Upon review of the relevant procedures, drawings and settings it was determined that a setting change was required to the protection relay. The setting was changed and the unit was returned to service on September 21, 2017. During the investigation, it was found that prior to the trip the power turbine had developed higher than normal vibration, though it was not the cause of the trip. Further investigation of the higher than normal vibration found the source to be a high temperature exhaust gas leak from the power turbine. Repairs were made and vibration levels returned to normal on October 7, 2017.

On October 15, 2017 the Happy Valley gas turbine experienced a trip while operating at near full load. Hydro's investigation determined that the trip was the result of the failure of an emergency fuel shut-off valve solenoid. The failure of the solenoid caused the 3-way valve to divert a portion of fuel away from the engine, as is its design. The reduced fuel flow was not able to sustain the required load and resulted in the unit shutting down. A replacement solenoid was sourced and repairs made with the engine released for service on November 9, 2017.

On May 13, 2018 the Hardwoods gas turbine tripped while operating in synchronous condense mode due to a system under voltage and current phase imbalance. The alternator experienced excessive vibration when attempting to restart the Unit on May 14, 2018. Extensive mechanical and electrical testing was conducted on the alternator to determine its condition, with no damage found prior to returning it to service on June 2, 2018.

On June 13, 2018 the Hardwoods gas turbine tripped due to excessive alternator vibration while being returned to service after a planned maintenance outage. Inspection of the Unit determined that cause of the vibration was a loss of lube oil due to a faulty check valve in the lube oil supply piping to one of the alternator bearings. The bearing which had the faulty check valve was found to be damaged and required replacement with a spare bearing. The Unit was released for service on June 30, 2018.

7.0 Gas Turbine DAUFOP Performance

The combined DAUFOP for the Hardwoods, Happy Valley and Stephenville gas turbines was 24.11% for the 12-month period ending June 30, 2018 (refer to Table 8). This is below the near-term assumption of 30.00%. The Hardwoods DAUFOP for the current period is 6.51%, which significantly exceeds the near-term assumption of 30.00%. The Stephenville UFOP for the current period is 51.35%, which is above the near-term assumption of 30.00%. Happy Valley's DAUFOP is 19.27% which is below the near-term assumption of 30.00%.

Table 8: Gas Turbine DAUFOP

Gas Turbine Units	**Maximum Continuous Unit Rating (MW)**	**12 months ending June 2017 (%)**	**12 months ending June 2018 (%)**	**Near-Term Planning Assumption (%)**
Combined Gas Turbines	125	8.68	24.11	30.00
Stephenville	50	13.10	51.35	30.00
Hardwoods	50	10.14	6.51	30.00
Happy Valley	25	0.00	19.27	30.00

The Holyrood (HRD) GT DAUFOP of 0.06% for the current period is better than the near-term assumptions of 5.00% (refer to Table 9).

Table 9: Holyrood GT DAUFOP

Gas Turbine Units	**Maximum Continuous Unit Rating (MW)**	**12 months ending June 2017 (%)**	**12 months ending June 2018 (%)**	**Near-Term Planning Assumption (%)**
Holyrood GT	123.5	2.46	0.06	5.00

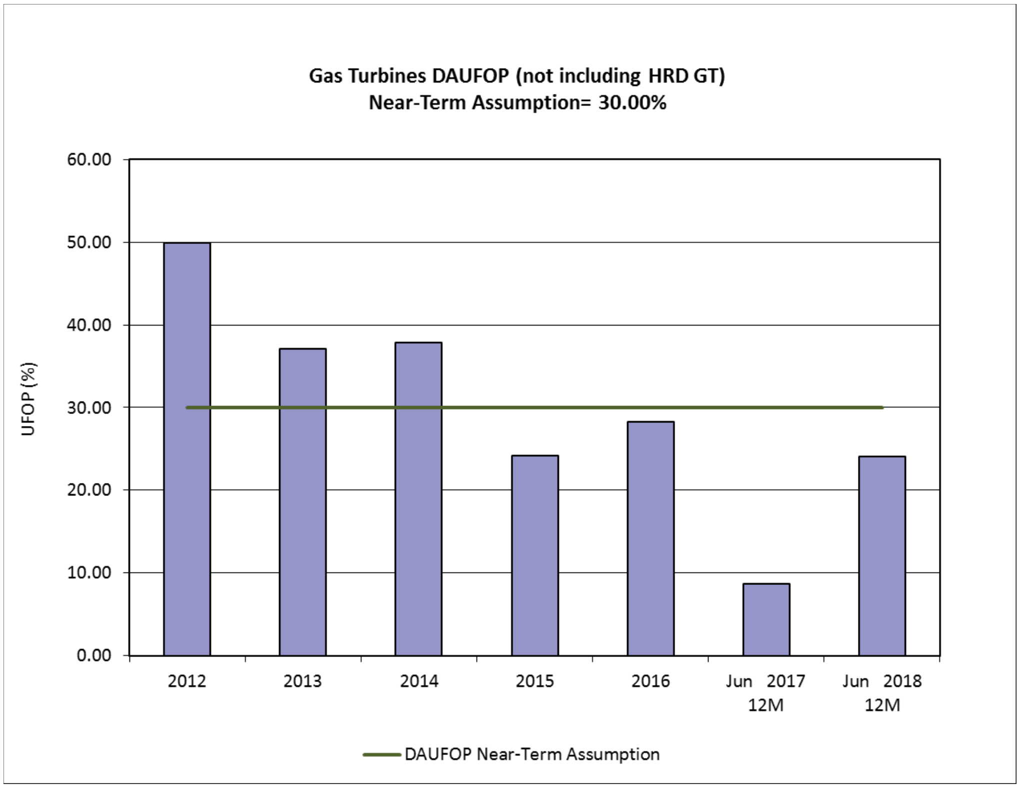

Figure 5: Gas Turbine DAUFOP – HWD/HVY/SVL Units

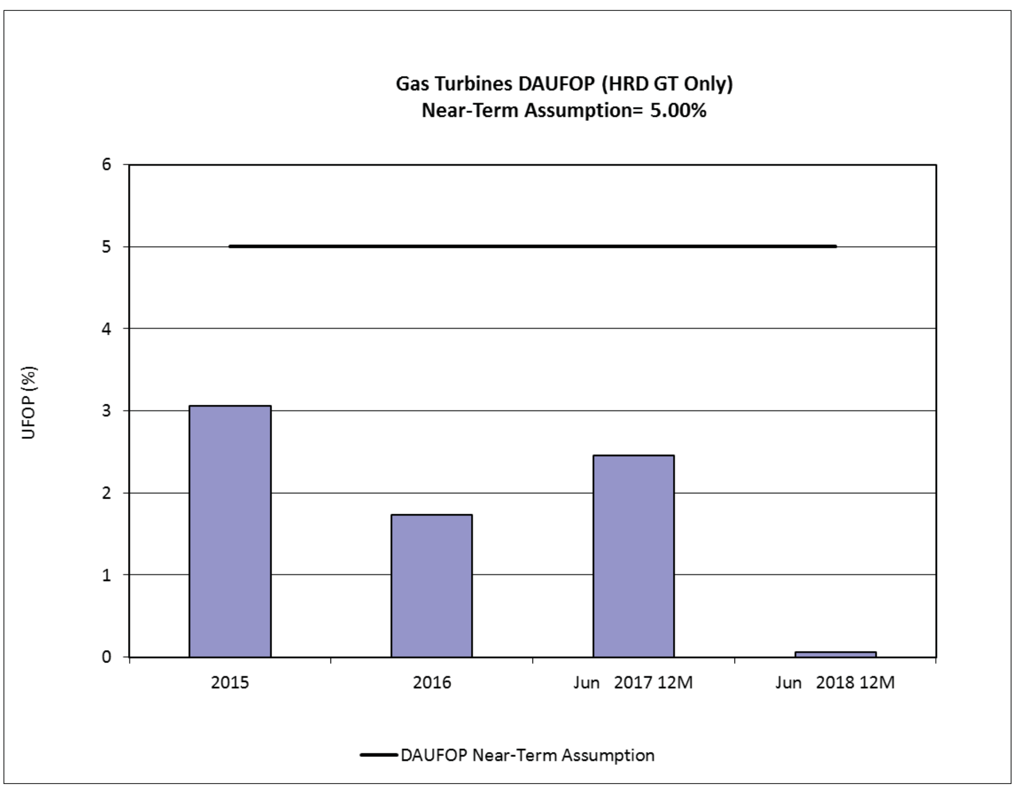

Figure 6: Gas Turbine DAUFOP – HRD Unit

The Stephenville gas turbine DAUFOP for the period was impacted by the unavailability of End A as a result of an exhaust bellows failure at Hardwoods gas turbine End A on December 28, 2017. End A was unavailable at this time due to issues with the power turbine rear bearing which requires the bearing to be replaced. Hydro decided to remove the bellows from End A at Stephenville and install it at Hardwoods End A to return that Unit to full capacity. It is currently expected that the Stephenville gas turbine will be returned to full capacity in August 2018.

The Hardwoods gas turbine DAUFOP for the period is impacted by the unavailability of End A due to an exhaust bellows failure on May 28, 2018. End A remains unavaliable with a planned return to service at the end of July 2018.