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

Final Report

Presented to:

The Board of Commissioners of Public Utilities
Newfoundland and Labrador

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Executive Summary

The power supply picture on the Island Interconnected System in Newfoundland and Labrador took a turn for the worse in 2016 with a number of events at Newfoundland and Labrador Hydro's (Hydro's) generating plants, including Holyrood, Hardwoods and Stephenville. Hydro prepared an Energy Supply Risk Assessment (ESRA) in May 2016 which included several scenarios in which Hydro's reliability criteria would be violated. In August 2016, Liberty issued its Phase Two report which, although focused on the post-Muskrat Falls environment, nevertheless concluded that "the need for pre-Muskrat Falls supply is likely". Subsequently the Board directed Hydro to prepare a new ESRA "that considers all risks and provides a risk-based recommendation on the need, timing, and amount, if any, for additional pre-Muskrat Falls supply".

In November 2016, Hydro completed the requested ESRA. Hydro concluded that there was no need for new pre-Muskrat Falls supply. At the request of the Board, Liberty has reviewed Hydro's report. This report provides our comments on Hydro's November 2016 ESRA report and our conclusions and recommendations regarding the need for additional pre-Muskrat Falls generation.

A. Risk Considerations

In evaluating Hydro's ESRA, Liberty concluded that there were a number of risks and uncertainties that may not have been adequately analyzed. These were issues in which Hydro may not have reflected the full exposure and uncertainty associated with key assumptions. These risk factors include:

- Outage risk at Holyrood, Hardwoods and Stephenville, which Liberty believes is much higher than assumed in Hydro's model.
- The load forecast, which is very pessimistic, having dropped 88 MW (for 2019-20) in the last 18 months. Hydro has not considered suitable sensitivities in its analysis.
- Further delays in Muskrat Falls, some of which have already been announced, which will increase the time during which current supply must suffice. Hydro is silent on this subject in the ESRA.

Hydro's risk of outages is overly optimistic in all three cases. A more accurate portrayal of the risk associated with each would result in lower reserve margins and higher probabilities of supply-related outages.

Hydro's analysis is also lacking because of its failure to analyze the uncertainties in its assumptions. An appropriate risk analysis will discuss the variability associated with each of its assumptions and communicate the various possible outcomes. A simple yes-no or pass-fail conclusion, without a clear explanation of the various other outcomes, is not a suitable analysis and does not meet the definition of a "risk assessment". While we do not disagree with Hydro's bottom line conclusion, it is our opinion that stakeholders should have a better understanding of the risk that Hydro's analysis may be wrong and the potential impacts that could result.

B. Recent Developments

When Liberty issued its Phase Two report in August 2016, all the events in 2016 up until that time were pointing to the need for new pre-Muskrat Falls capacity. This picture began to change in late 2016 with the following major developments:

- The addition of the 110 MW recall power, which was not included in the earlier ESRA, equates to the addition of the new CT we thought may have been needed. In that sense, our recommendation for new pre-Muskrat Falls supply has already been fulfilled, and supply risks greatly mitigated.

- The load forecast that accompanied the November ESRA included another precipitous drop in forecasted peak demand, the second in just six months. This reduced forecasted demand in 2019-20 by 88 MW from the forecast prepared in mid-2015. Coupled with the recall power, this changes the supply-demand equation by nearly 200 MW.

- A major driver of the supply concerns was the early 2016 problems with the thermal units, the most serious of which were the de-ratings and heightened DAFORs at Holyrood. A report by AMEC, Hydro's external consultant, concluded that the de-ratings for the units could be eliminated which reduces the severity of the Holyrood outlook. Significant risks still remain, but the risk of continued boiler tube problems and a long-term de-rating of the three units, which had been a concern in early 2016, appears to have been eliminated.

These three factors, none of which was in place in August 2016, have changed the supply outlook considerably.

C. Conclusion

All the recent changes work against the need for more pre-Muskrat Falls generation. The addition of the recall power, assuming all technical requirements and commercial arrangements are in place, adds the generation Liberty suspected was required, effectively rendering the supply question moot. Given the other recent developments, it is possible that new generation might not be justified even in the absence of the recall power, at least for a few years.

Our primary recommendation is that new pre-Muskrat Falls supply not be pursued further at this time. Prudent planning would suggest that this conclusion be revisited in one year or sooner if major assumptions change. Further, we expect that a decision on new post-Muskrat Falls supply needs will be made in the next year and, to the degree that a CT solution is required, the desirability of advancing that CT into the pre-Muskrat Falls window should be evaluated.

D. Other Recommendations

In addition to the above recommendation on the pre-Muskrat Falls supply need, Liberty has also developed recommendations on (1) the management of risk factors, (2) clarification of certain elements of the current ESRA, and (3) suggestions for future ESRAs. These are included at the end of Chapter VI.

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I. Introduction

On October 13, 2016, the Newfoundland and Labrador Board of Commissioners of Public Utilities (the Board) directed Newfoundland and Labrador Hydro (Hydro) to file the following:

> *A report by November 30, 2016 on a comprehensive review of the energy supply for the Island Interconnected system as recommended by Liberty in its report dated August 19, 2016, that considers all risks and provides a risk-based recommendation on the need, timing and amount, if any, for additional pre-Muskrat Falls supply. This report shall include all current information on the load forecast and the status of generating units and shall address specifically the condition of the thermal units at Holyrood, the combustion turbines at Hardwoods and Stephenville and the Bay d'Espoir Penstock 1.*

The referenced Liberty report had concluded that "the need for pre-Muskrat Falls supply is likely"[1], and that conclusion prompted Liberty's recommendation for a comprehensive review of supply requirements and the Board's directive for a thorough analysis.

On November 30, 2016, Hydro filed the required report with the title "Energy Supply Risk Assessment" (ESRA). Subsequently, the Board requested that Liberty review the ESRA to determine if any of the conclusions and recommendations in its August 19, 2016 report were affected by the analysis in the ESRA, with a specific focus on addressing the need, if any, for new supply prior to Muskrat Falls supply.

A. Background

Events in early 2016 created additional concerns regarding the adequacy of power supply on the Island Interconnected System (IIS). Concerns first arose with consecutive winters characterized by major interruptions in 2013 and 2014. The latter outages triggered a major investigation by the Board. Liberty was retained in early 2014 to assist in the investigation.

Liberty completed its initial work and issued two reports: an interim report on April 24, 2014 and a final report on December 17, 2014. Liberty concluded in the interim report that "a continuing and unacceptably high risk of outages ... remains for the 2015-17 winter seasons". Hydro addressed this risk by installing a new 120 MW CT at Holyrood in a short period of time and the unit was in-service for most of the winter of 2015-16. Equipment issues continued in both the winters of 2014-15 and 2015-16, and the new 120 MW CT was an extremely valuable part of the generating fleet to meet supply.

Although conventional wisdom suggested that the 120 MW addition plus the procurement of curtailable load would end any further concerns regarding pre-Muskrat Falls capacity[2], this did not hold true for long. In its final Phase One report (December 2014), Liberty explained that shifting assumptions and findings had somewhat offset some of this much-needed new capacity. Offsets included the use of a P90[3] load forecast (versus the prior P50), increased awareness of higher

[1] Page 11

[2] At that time, Muskrat Falls capacity was expected for the winter of 2017-18 at the earliest.

[3] A P90 forecast suggests that the probability that the forecasted peak will be exceeded in a given year is only 10%, compared to a 50% probability for a P50 forecast. Hydro had previously employed a P50 forecast.

system losses in upset conditions[4], and increased focus on reserve margins in addition to LOLH which was part of the supply planning criteria used by Hydro. Despite these offsetting factors, Liberty stated its reluctance to recommend more additional generation, especially with such a recent significant addition and with Muskrat Falls on the short-term horizon.

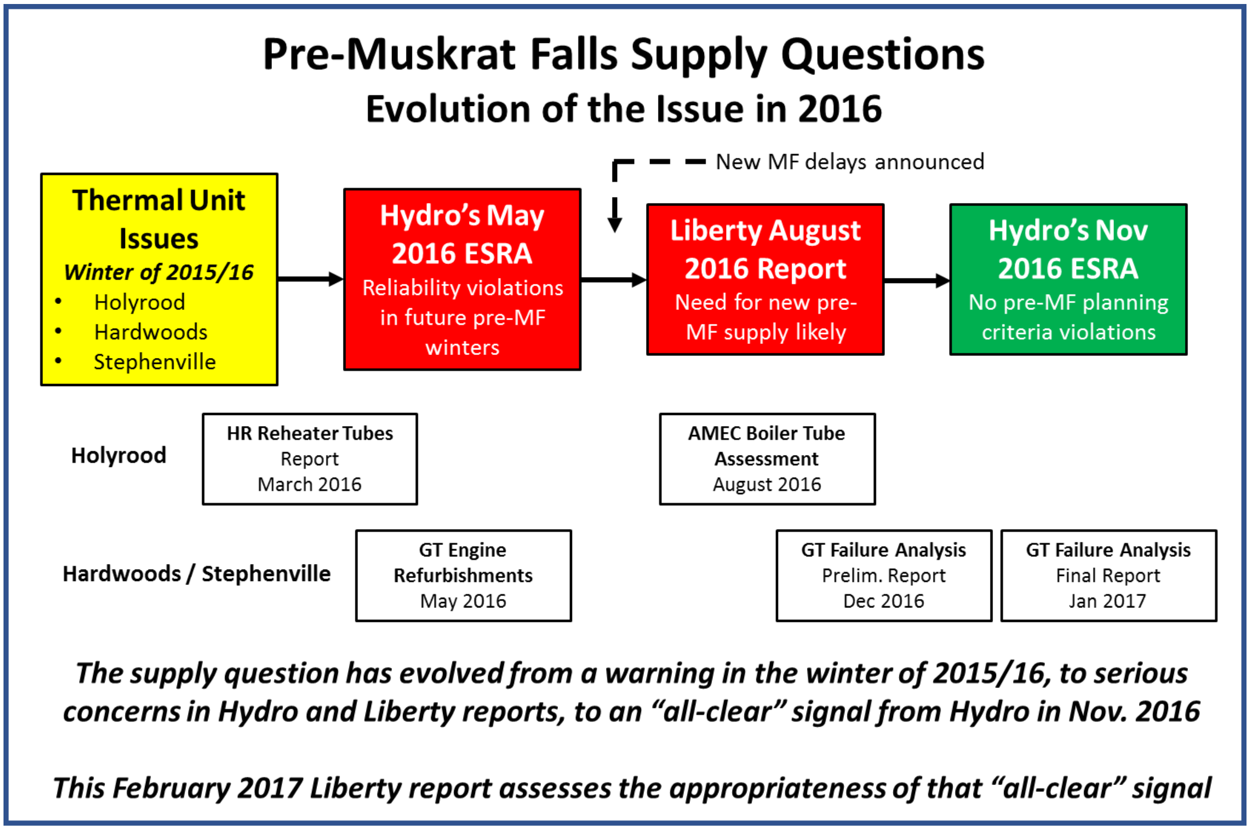
Liberty observed that three factors could be considered to reduce supply risk: more supply, less load, or higher unit availability. The first two options had been effectively exhausted, leaving plant availability as an urgent priority. The Board directed that a number of initiatives be implemented to improve plant availability. Hydro agreed and escalated its work to improve the reliability of its generation.

Despite Hydro's aggressive response, issues of concern to supply adequacy continued. There were significant events at Hardwoods and Stephenville and, in March 2015, outages resulted from a system voltage collapse. These occurrences added to lingering concerns that risks of future outages were real. Most importantly, the March voltage collapse raised yet again concerns Liberty has repeatedly communicated regarding Hydro's operating philosophy. The March 2015 event highlighted, in our opinion, the continuing concern over Hydro's operating philosophy and culture as well as the organization's skills and capabilities in reliability engineering and analysis. These concerns were repeated during the prudence proceedings before the Board later in 2015[5].

Reliability concerns were therefore significant entering the winter of 2016. The events that were to then unfold during 2016 led to our conclusion that risks were getting too high. The diagram below illustrates the sequence of events that brought us to this conclusion and the need for Hydro's November 2016 ESRA.

[4] The increased dependence on off-Avalon generation in the January 2014 event resulted in sharply higher system losses.

[5] We note that these critical questions have received no response from Hydro, although the Board has recently set a March 30, 2017 deadline for such response.



Problems began with issues at Holyrood, Hardwoods and Stephenville that can fairly be characterized as extreme. The Board requested that Hydro evaluate supply risk and, in May 2016, Hydro issued a report that concluded its planning criteria would be violated in coming years. At about this time, Nalcor announced significant delays to the Muskrat Falls capacity. Full operation was now expected in the winter of 2020-21. Liberty viewed these two results, criteria violations and significant time until new capacity would be available, as significantly increasing the risks to the adequacy of IIS supply. This prompted the conclusion in our August 2016 report that it was increasingly likely that new generation in some form would be required before Muskrat Falls.

Other important related events in 2016 included:

- An initial report on the Holyrood tube failures and the need to de-rate the units. This represented a serious setback and threat to reliability.
- A subsequent AMEC report on the Holyrood failures which provided a much more positive assessment.
- A May 2016 report on the need to refurbish engines at both Hardwoods and Stephenville.
- A December 2016 preliminary report on the causes of the Hardwoods and Stephenville failures.
- A January 2017 final report on root causes of the Hardwoods and Stephenville failures.

The degree to which these events tended to improve or detract from supply reliability is discussed later.

This sequence of events culminated in Hydro's ESRA of November 2016. We characterize that report as giving the "all-clear" signal as a response to all of the supply warnings that emerged throughout the year. This Liberty report will evaluate the ESRA and provide our opinions on the validity of its conclusions, the ramifications for IIS reliability and the potential need for new generation pre-Muskrat Falls.

B. The Phase Two Investigation

The Board's Phase Two investigation was originally intended to focus on reliability questions associated with the integration of Muskrat Falls, the Labrador-Island Link (LIL), and the Maritime Link (ML) with the IIS. As we observed above, conventional wisdom was that no new generation would be required before Muskrat Falls. As the events of 2016 unfolded, the Board noted that there were significant and continuing risks to the adequacy and reliability of supply on the IIS, given deteriorating unit performance and further delays in the Muskrat Falls in-service date.

The pre-Muskrat Falls supply issue necessarily was moved to the front burner. The fundamental work of Phase Two continues, but the urgency of dealing with potential near-term power shortages requires that attention focus there as a priority.

One Phase Two issue is discussed here because it might impact decision-making on the pre-Muskrat Falls supply question. In our August 2016 report, we also suggested that there was a potential need for added capacity after Muskrat Falls is in service. A loss of the LIL in peak conditions will result in loss of load on the IIS. If that LIL failure extends for several days, or weeks, such as in the event of one or more tower failures, extended outages are possible. New supply would mitigate both the frequency and duration of such outages.

If new capacity is required post-Muskrat Falls, and that capacity takes the form of a new CT on or near the Avalon, then it makes sense to consider an earlier installation so as to also satisfy pre-Muskrat Falls risks. On that basis, any Phase Two decisions in this regard could influence the pre-Muskrat Falls decision-making.

C. Planning Criteria

Since 2014, Hydro has steadily but significantly made changes in its power supply planning process. That process had maintained consistent practices and survived reviews by external consultants and others. The historical underpinning of supply planning for the IIS was the notion that an isolated system could not afford the same level of reliability as interconnected North American systems. Hydro long ago adopted a loss of load probability that was effectively double that used throughout North America. The accepted loss of load probability (LOLP) is equal to 0.2 per year, or one supply-related event every five years[6]. In its modelling, Hydro expressed this as a loss of load hours (LOLH) of 2.8 hours per year.

[6] The general standard in North America is 0.1 per year, or one supply-related event every ten years.

In our earlier reports, we expressed our concerns that perhaps such a standard was losing its relevance. The outages of 2013 and 2014 influenced the perception of stakeholders regarding reliability. Further, the consequences of extended outages in Newfoundland have grown considerably, especially considering the penetration of electric heat. High dependence on electric heat means that an extended outage in severe winter weather is no longer just an inconvenience but is potentially a matter of life and death. And finally, while the geography of the Province is indeed quite unique, there is nothing unique about today's IIS communities that would dictate substandard reliability planning criteria.

These are concrete reasons for a higher standard for electric service. Also, the old argument that "we cannot afford better" may be outdated in a system that is currently investing more than $11 billion in new generation and associated facilities, an amount that would dwarf the traditional cost of moving from an LOLP of 0.2 to an LOLP of 0.1.

It must also be noted that Hydro is not likely to have a choice in the matter for much longer. NERC/NPCC standards, which will apply to Newfoundland in the future, require an LOLP of 0.1. Hydro "does not plan to comply with this criteria until at least after the IIS is connected to the North American grid".[7]

Liberty agrees that for the purpose of pre-Muskrat Falls supply analysis, the more relaxed LOLH of 2.8 should be utilized. It is nonetheless important to note that the forces in play are all pushing in the other direction and the long-accepted criterion may not be acceptable in the near future.

D. Measures of Supply Reliability

In our December 2014 report, we suggested that a narrow focus on LOLH was not appropriate. We explained how Hydro's modeling assumptions vis-à-vis thermal unit outage rates, produced target reserve margins that seemed too low. For example, if a utility had very reliable generating units, to the extent one could assume they were almost always available, the utility would need less overall generation and hence could operate with less reserves. The allowable reserves in Hydro's calculations suggested that this was the case for Hydro, but we know that such a characterization of Hydro's thermal units is wrong[8].

The translation between LOLH and reserve margins is super-sensitive to thermal unit outage rates. Hydro has in fact indicated that the primary influence in its supply assessments is the unavailability of the Holyrood thermal units[9].

To its credit, Hydro has repeatedly responded in a positive way as such important questions arose through the years. Hydro increased its planning reserve target, in part to reflect more reasonable values flowing from the 2.8 LOLH. In addition, Hydro has sought still better measures and is now also using expected unserved energy (EUE) as another indicator of supply adequacy. There is no formula to combine these indicators into a black-and-white result, but each sheds light on the

[7] PUB-NLH-628
[8] Please see Page 19, "Defining Adequate Reserves", in Liberty's final Phase One report for a more complete explanation.
[9] May 2016 ESRA, Page 10

reliability question. Further, reserve margins and EUE have the advantage of providing a physical insight that, for most people, LOLH lacks.

II. Generation Reliability

A. Measures of Unit Reliability

It has been noted above that thermal unit availability is the most influential determinant of Hydro's supply adequacy. It is essential to settle on a good measure of availability, recognizing that the correct parameter will be a function of the characteristics of the generation. Unfortunately, the indicators that are generally used and universally accepted can produce misleading results, especially for less than base load units. A rigid application of those indicators in a simple plug-in way may not produce the right answer. Given the critical role of the Holyrood units for supply and the 2016 events relating to the units, it is important to understand the limitations of such measures.

The widely-used measures of reliability range from the very simple to the near-indecipherable. Adding confusion is the difference in some terms as utilized by the North American Electric Reliability Corporation (NERC) and its GADS system, and the Canadian Electricity Association (CEA) and its ERIS system. CEA terminology is used in this discussion. The table below summarizes the relevant terms:

Industry Standards for the Measurement of Unit Reliability as Related to Forced Outages

Indicator	US Term	Canadian Term[1]	
Forced outage rate	FOR	FOR	Considers all service hours
Demand forced outage rate	FORd	UFOP[2]	Considers hours in demand period only
Equivalent forced outage rate	EFOR	DAFOR[3]	Includes de-ratings proportionately
Equivalent demand forced outage rate	EFORd	DAUFOP	Includes de-rates and only the demand period

[1] The intent of the US and Canadian terms is the same, but the indicators and their formulas are not necessarily the same
[2] UFOP is Hydro's measure of choice for peaking units
[3] DAFOR is Hydro's measure of choice for Holyrood

Source: IEEE Standard 762

The key differentiating factor among various reliability indictors is the timeframe over which the unit's running time is measured. At the simplest extreme, that timeframe is 8,760 hours per year, and we could theoretically divide the forced outage hours by 8,760 to get a measure of reliability. But this would be overly optimistic, because there are hours in the year when the unit is in a planned outage condition or off line for some other valid reason, such as economy. It is therefore appropriate to remove those hours, and the result is the traditional FOR. Note that dividing by a smaller number of hours has the effect of increasing the forced outage rate.

Another key feature of the FOR is its binary, or two-state, assumption. The unit is considered on or off, with no penalties for partial load. The unit must be off line altogether to be considered in a forced outage condition. This produces an overly optimistic outlook, because it ignores cases where a unit may have been forced to de-rate, instead reporting de-rated hours as the equivalent of 100 percent output. Consider Holyrood Unit 3 during the 2014 emergency. The unit was de-rated by 100 MW due to the failure of a forced draft fan motor. This had serious consequences, yet did not count as a forced outage in the calculation of the forced outage rate. For those purposes, the unit was treated as if it operated at full power.

An adjustment to the traditional forced outage rate is therefore necessary to account for such forced de-ratings. The result is a de-rating adjusted forced outage rate, or DAFOR. Consider a unit forced to operate at only 50 percent of capacity. For each hour of such operation, the unit will be assumed to be in a forced outage for 50 percent of the time. The resulting DAFOR will be 0.5 for the period in which this condition persists.

Another factor that we may wish to consider is created from the notion that we do not really care about a unit's reliability when the unit will not be called to run anyhow. The UFOP considers only the hours when the unit is needed. A unit that is scheduled to run for four on-peak hours will be measured only against those hours. This distinction seems especially important to the Hydro CTs. If the units fail in the peak season, as they did in 2016, there is no urgency to make the necessary lengthy repairs since the units would not be needed again until the following winter. If we did not adjust for the demand period, and perhaps used DAFOR instead, the units would be severely punished for the off-season unavailable time. The use of UFOP greatly advantages the CTs in this regard, but rightly so.

Another advantage offered by UFOP to the CTs is the failure to consider de-ratings, but the appropriateness of that advantage is much more in doubt. Consider that the engine failures at Hardwoods and Stephenville only disable half a unit. For that period, UFOP treats the unit as being 100 percent available. For that reason, we would disqualify UFOP as a reasonable measure for the Hydro CTs.

In understanding each metric, one will note that the demand period for a highly utilized (base load) unit will be near 100 percent. Accordingly, the anticipated value of the demand-related parameters will tend to merge with their non-demand-related cousins. So, EFORd = EFOR and DAUFOP = DAFOR for a base load unit.

There are many factors by which to judge which measure is right for a given unit, and we will examine them when we discuss each unit separately. Curley argues that EFORd (or DAUFOP) is a superior measure for any type of power plant or any mode of operation (base, intermediate, peak).[10] His logic would suggest that:

DAUFOP (or EFORd) captures both de-ratings and the demand period

- Hydro's use of DAFOR is inferior because of its lack of the demand consideration.
- Hydro's use of UFOP is inferior because of its lack of the de-rating consideration.

We will examine both questions further below.

B. Holyrood

The current importance of Holyrood to the IIS cannot be overestimated, not only for its size but for its electrically strategic location. If the units were of high reliability, the risks to pre-Muskrat Falls supply would be significantly reduced. But that is not the case.

[10] Reliability Analysis of Power Plant Outage Problems, G. Michael Curley, President, Generation Consulting Services, LLC, Pages 37 and 65: http://famos.scientech.us/PDFs/2013_Symposium/Reliability_Analysis_of_Power_Plants_Curley.pdf

There is no disagreement that Hydro has worked hard to maintain unit reliability until it is safe to retire the units, presumably after Muskrat Falls and the LIL have demonstrated their dependability. That day seems to be at least five years into the future and maybe more. The IIS will therefore be required to continue to rely heavily on Holyrood.

1. Boiler Tubes

Holyrood units 1 and 2 experienced a series of tube failures in early 2016, specifically in the lower reheat section of the boilers. The nature of the failures, their applicability to all three units, and Hydro's perceived need to de-rate all three units to mitigate new failures, represented a blow to Hydro's supply situation and raised the specter of the units limping along in a high-risk state for their remaining life.

The debilitated condition of Holyrood was reflected in the May 2016 ESRA in the form of (a) a 60 MW reduced plant capability and (b) varying assumptions for DAFOR, ranging from 10 percent to 24 percent. This produced reliability criteria violations when DAFORs of 19 percent and higher were assumed. In these cases, the criteria violations were presented by Hydro in terms of expected unserved energy (EUE) in excess of the criterion of 300 MWh per year.[11]

In August 2016, AMEC completed a report on the boiler tube issues at Holyrood. AMEC concluded that "there is a low risk of boiler tube failures due to wall thinning on Units 1 and 2, operating at current pressure, with no de-rate, to 2021." There were qualifications to this conclusion and concerns expressed regarding Unit 3, but the favorable nature of this analysis was very positive given the earlier pessimistic prognosis. Liberty has no basis to question AMEC's analysis. There are additional steps required by Hydro, including further inspections and work on Unit 3, but the AMEC disposition was as close to a clean bill of health as anyone could have reasonably expected.

Notwithstanding this AMEC conclusion, Hydro has elected to operate Holyrood at lower levels, although Hydro has not characterized this as a "de-rate". The planned operating levels of the 3 units are 150 MW, 150 MW and 135 MW respectively, nearly identical to the de-rated levels of the May 2016 ESRA[12]. The difference is that Hydro will run the units at higher levels if emergency needs dictate. Hydro has indicated that there are no limitations on how long the units will be allowed to operate at the higher levels.

The impact of this pseudo de-rate for supply calculations is nil, since the higher emergency outputs used in the model are credible. Perhaps the only real significance for our purposes is the apparent concern by Hydro for the units' fragility. Suffice it to say that if Hydro is concerned, the Board and other stakeholders should be too.

2. Other Holyrood Issues

In the November 2016 ESRA, Hydro explained other Holyrood operating and maintenance issues that could potentially impact the supply assessment. These include continuing problems with the new variable frequency drives for the FD fan motors, air flow limitations in the units 1 and 2

[11] Internal Hydro research led to the conclusion that 300 MWh EUE was the equivalent of an LOLH of 2.8 hours.
[12] PUB-NLH-632

boilers that can restrict output, and issues with the turbine governor controls. None of these appear to rise to the threat levels offered by the boiler tube issue. This does not temper the contribution of other influences on Holyrood reliability – quite the contrary. Age and deteriorating condition will continuously bring new problems, whether potentially catastrophic (like the boiler tube matter) or more narrow issues.

In any event, it would not be prudent to expect better performance at Holyrood. Another surprise can occur at any time. That is simply the reality of life with units nearing their end-of-life.

3. Estimating Holyrood reliability

Hydro has made two key assumptions in determining the impact of Holyrood reliability on power supply adequacy:

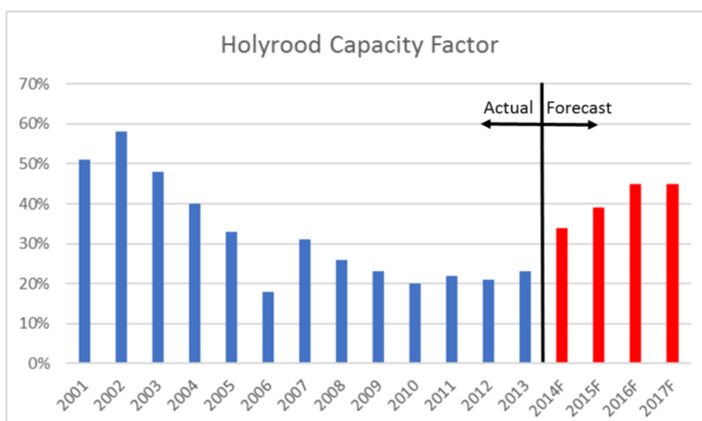
- DAFOR is the correct measure to use for Holyrood in the supply analysis
- 14 percent is the correct estimate for DAFOR.

These simple assumptions are pivotal to the conclusions reached in the November 2016 ESRA. Holyrood unavailability is the key influence in the analysis, and these two assumptions dictate how that unavailability is reflected in the model. Given the importance of these assumptions to the level of confidence in the conclusions of the November 2016 ESRA, a more detailed discussion is appropriate.

a. Is DAFOR the best measure?

We earlier discussed DAFOR's lack of a demand period consideration. This is irrelevant for a base load unit since, in that case, essentially all hours are in the demand period and hence DAFOR and its associated demand-related parameter (DAUFOP) converge to the same value. DAFOR is therefore a sufficient measure for highly utilized plants.

Hydro has explained its use of DAFOR at Holyrood in PUB-NLH-635, where Hydro characterized Holyrood as "base load units". A consideration of Holyrood's annual capacity factors contradicts such a characterization. The accompanying chart illustrates that since 2003, capacity factors have been under 40 percent, and less than 25 percent in most years.



Source: Hydro 2017 Capital Budget Application, Holyrood Overview, July 2016

Rather than argue about definitions, however, we should maintain focus on the objective, which is to derive a reasonable estimate for the probability that a unit will be available when called upon. Industry data, as published by Curley in the paper previously cited, suggests that DAFOR is very likely to be *higher* than DAUFOP, with the hypothesized gap being about 7 percent for oil-fired units. This argues that DAFOR is not the best fit, but its use might be appropriate and, in fact, conservative.

b. What is the best estimate for DAFOR?

Hydro has chosen DAFORs of 15 percent, 10 percent, and 18 percent respectively for the three units, which averages 14 percent. Liberty does not believe that Hydro's logic in deriving those estimates hangs together. The units are nearing 50 years of age, are in declining health, and would have been retired by now if the capacity were not so badly needed. In fact, the units will be retired (except for Unit 3 synchronous condensing) as soon as MF and LIL are proven a reliable substitute. If this characterization of deteriorating condition is appropriate, it would not be prudent to assume that the performance of the last five years (DAFOR = 16 percent)[13] will be representative of the next five years or, as Hydro suggests, even better. We believe that a superior choice would be the assumption that performance will be worse than the last five years, so that a DAFOR > 16 percent would seem a more logical choice.

This might normally be considered as excessive fine tuning, but the May 2016 ESRA produced reliability violations when DAFOR > 14 percent was assumed, so our proposed "fine tuning" may be significant. Hydro explained why it selected 14 percent in its response to GRK-NLH-138:

> *"Since that time, the AMEC analysis and additional Babcock and Wilcox analysis has been completed, providing a better understanding of the boiler tube health. Through the results of both of these assessments and a thorough review of recent performance issues, Hydro identified a robust set of parameters resulting in a projected DAFOR of 14% for the study period."*

We are unclear as to the nature of the "robust set of parameters", but the 14 percent DAFOR is not supported by either the five-year data or Hydro's more specific outage assumptions. Those underlying assumptions are detailed in the November 2016 ESRA, Appendix A, Page 3. Hydro has assumed forced outages as follows:

Unit 1: 1 @ 30 days and 8 @ 24 hours, all of which are during the operating season
Unit 2: 1 @ 30 days and 8 @ 24 hours, all of which are during the operating season
Unit 3: 1 @ 30 days and 7 @ 24 hours, all of which are during the operating season

The impact on DAFOR of 38 days of outages in a 120-day operating season should be obvious. In such a situation, the best possible DAFOR during the operating season would be 32 percent. Although Hydro specifically assumed the outages during the operating season, it calculated DAFOR as if these outages were spread over the entire year, which would obviously produce a much lower DAFOR. For purposes of capacity needs, only the peak season will be influential. Liberty believes then that Hydro's assumptions require a 32 percent DAFOR. Alternately, Hydro could withdraw the assumptions it made regarding forced outages "during the operating season". Hydro disagrees and in PUB-NLH-634 defends its approach. Liberty nonetheless concludes that a 14 percent DAFOR and Hydro's peak season outage assumptions should not coexist.

In relating to supply risk, we should recognize that fine tuning of DAFOR is neither the problem nor the solution. The circumstances at Holyrood are such that we must be concerned about the risk of more catastrophic failures that can lead to serious system issues, and not necessarily just routine

[13] The November 2016 ESRA, Appendix A, Page 2 reports 2012-16 (projected) DAFOR as 16%

outages. For most units, that catastrophic risk is considered to be near zero in supply analyses, but is that reasonable for Holyrood? The catastrophic loss of Unit 1 in 2013, the simultaneous loss of all three units in 2014, and the boiler tube issues in 2016, all occurring in the peak season, represent dangerous scenarios that can lead to supply emergencies and system failures. The risk of such high impact failures cannot be adequately reflected in a reasonable DAFOR, but ignoring them in a risk analysis is a problem.

4. Holyrood Reliability Conclusions

This leads us to the following conclusions on how Holyrood's performance expectations should be included in the ESRA:

- DAFOR does not consider reliability in the demand period but is nonetheless likely to be an appropriate, and perhaps conservative, measure for gauging unit reliability in the supply model.
- There is no basis to assume that future Holyrood performance will be better than, or even equal to, recent (five-year) performance.
  - Hydro's use of a 14 percent DAFOR, versus five-year experience of about 16 percent, is therefore inappropriate.
  - Some additional deterioration from recent performance is reasonable to expect, given the age and condition of the units. Note that a 19 percent DAFOR in the May 2016 ESRA produced reliability criteria (EUE) violations.
- Perhaps more important than fine-tuned DAFORs is the threat of large failures that might have a system-wide impact, such as extended unit forced outages or multiple unit failures in peak season, such as were experienced in 3 of the 4 peak seasons in 2013-16.
- The current ESRA over-estimates Holyrood's ability to reliably support the system pre-Muskrat Falls.

C. Hardwoods and Stephenville

The performance and reliability of the Hardwoods and Stephenville CTs have been continuously weak. The failures of engines on both units in the 2016 peak season were significant events that continued their poor track record. The nature of the failures, and Hydro's response to them, only raises more concerns that these units are undependable. Hydro's root cause analysis for each unit has resulted in miscellaneous "improvements" with no assurance that they address the root causes of the failures, nor that they will improve the reliability of these units in a meaningful way. Further, Stephenville has been plagued by vibration issues since the 2016 failure and, to our knowledge, has yet to return to full output.

Liberty's scope in analyzing the 2016 failures is limited to understanding how and if those failures influence the need for more supply pre-Muskrat Falls. Our conclusion, as demonstrated below, is that the 2016 evolution and the 2017 status only lessens the confidence that these units will be available when called upon.

1. The Hardwoods 2016 Failure

On February 8, 2016, a combustion can failure, with the resulting debris damaging other engine components, occurred in the Hardwoods End A.

Hydro retained Alba Power Ltd. to conduct a root cause analysis of the incident. Hydro concluded that "the root cause of the engine failure could not be conclusively determined". Hydro's conclusion is perhaps literally correct, but seems incorrect when viewed in the context of Alba's analysis. Alba identified six root cause candidates and characterized one as not possibly a root cause, one as unlikely, three as possible, and one as likely. The "likely" cause, according to Alba, was the engine controls. They explained potential circumstances for which the controls could have caused overheating, but then also added that "the gas turbine ran on for a period of time when the controls system should have shut down the gas turbine"[14]. This seems to suggest that, not only were controls at fault, but they were at fault via two different mechanisms: causing the high temperatures in the first place and then failing to shut down the unit in a timely way.

In response to PUB-NLH-653, Hydro explained that the trip settings on the unit were incorrect, thereby addressing the failure to shut down. Hydro did not address the initial concern of a potential issue in the controls and seems to have dismissed it.[15] We assume that Alba did not make its "likely" conclusion lightly. For our purposes in evaluating unit reliability, we can only assume that any problems present in the control system that caused the failure are "likely" to still be lingering there.

2. The Stephenville 2016 Failure

On March 26, 2016, Stephenville End A suffered bearing failures resulting in substantial damage. Hydro retained Performance Improvements Ltd. (PI) and Alba to study the root cause of the failures.

The PI analysis is thorough and focused; nevertheless, it may not be fully accurate. Hydro takes exception to many of its conclusions. Hydro agreed that "an oil change cannot be confirmed to have been completed after a previous oil test indicated that the oil was beyond acceptable limits"[16]. PI noted that "the oil continued in use in the degraded and worsening condition for at least a year before the bearing failure".[17] Hydro now reports that neither its own nor PI's conclusion was correct; i.e., the previous oil test was *not* beyond acceptable limits. The testing lab's initial conclusion applied to reciprocating engines, and not the Stephenville unit. Hydro knew this at the time (2014) and therefore believed an oil change was not needed. In PUB-NLH-642, Hydro notes that PI was not informed of this, nor was this included in Hydro's January 2017 failure analysis, having come to light only very recently. Liberty has no reason to question this unusual evolution of events.

But this leaves the simple question of "was the oil bad or not"? In the January 2017 final report, Hydro agreed that the oil was bad, but retracted that conclusion in PUB-NLH-642. Hydro also reports that the post-event oxidation level was 5, better than the 66 recorded in the earlier test a year before the failure. PI stated that such a result was impossible, and in PUB-NLH-644, Hydro did not provide an explanation. Hydro never claims that the oil was compliant at the time of the event, although its responses to related questions seem to imply that.

[14] Alba report, Page 10
[15] Hydro does report that a review of unit acceleration and deceleration curves is underway (PUB-NLH-654)
[16] GT Failure Analysis Final Report, Page 10
[17] PI Report, Page 8

In its final report, Hydro characterizes the oil-related root cause as "not entirely conclusive", and perhaps that is now the case. But it clearly was not the case at the time the report was written. There was no basis at that time to say the oil-related conclusions were "not entirely conclusive".[18]

PI also raises several other issues that may be contributing and should be considered:

- PI believes the lube oil filter was mis-sized by a factor of 50, thereby being ineffective in screening contaminants. Hydro does not address this in the January 11, 2017 report, but notes in PUB-NLH-645 that Alba has used this size filter in overhauls and Hydro would not change this without OEM direction. There is no indication that Hydro plans to pursue this any further.

- PI concluded that late activation of the vibration detection system was the reason for the *extent* of the damage (as opposed to the cause). The vibration system did not operate early enough to protect the unit. Hydro reports that an incorrect setting was in place after a 2014 upgrade of the system. The Hardwoods system was also upgraded but its settings were correct.[19]

- PI concluded that metal particles were continuously circulating within the lube oil system as a result of the filter in the return line becoming blocked. Blockage was apparently extensive enough to activate the bypass of the filter. Hydro believes that the filter only became blocked as a result of the event and justified this because (1) the bypass alarm did not activate and (2) the majority of debris in the filter was failure debris.[20] It is not clear why this difference of opinion was not resolved before PI's report, or if PI agrees with Hydro's conclusion.

The Stephenville failure, as well as the subsequent analysis, exhibits the type of human and process errors for which Liberty has repeatedly expressed concerns. We will discuss this issue later, but suffice it to say that correction of such human factors remains the primary critical path to reliability improvement. Hydro seems to understand and be addressing the Stephenville issues. Nevertheless, the new vibration issues, encountered while trying to get the repaired unit back in service, are not proving easy to solve. The bottom line is there is little basis to expect improved performance at Stephenville.

3. Estimating CT Reliability

Hydro has no choice but to assign some quantitative measure to the reliability of the CTs. But it is hard to see how any measure can help us better understand the units' recent reliability and an inevitable slide to lower expectations. The numbers simply do not communicate the lack of dependability of these units. Consider for example the published 2016 UFOP for Hardwoods (3.6 percent).[21] We presume the calculation is correct, but is this a common-sense representation of Hardwoods' reliability? We think not. UFOP is a two-state measure, on or off. It does not

[18] Hydro has raised doubts as to cause, but not until *after* the report.
[19] PUB-NLH-648
[20] PUB-NLH-647
[21] November 2016 ESRA, Appendix A, Page 5, Table 5

recognize de-ratings, so a loss of one end of a CT is not considered an outage for UFOP purposes.[22] This argues strongly that UFOP is of little value, at least as applied to the reliability of Hardwoods and Stephenville. Hydro acknowledges this in reporting that "Hydro is also evaluating if an additional measure is appropriate for the gas turbines".[23]

The use of UFOP is producing answers that we believe are wrong. Hydro's conclusion is that "both plants [Hardwoods and Stephenville] have had improved reliability in recent years".[24] This might be true from an analysis of UFOPs, but the suggestion that things are getting better at Hardwoods and Stephenville has no basis in reality – the precise opposite is painfully apparent. Please refer to Liberty's discussion of these units in our August 2016 Phase Two report, Page 9. Note also that Stephenville, at this writing, has still not fully returned to 100 percent service since the March 2016 failure.

We believe that the UFOP data as applied to these units, and Hydro's application and interpretation of the data, are invalid. Perhaps the recommended 20 percent, as an arbitrary indicator of reliability intended only to fill a blank space in the model, is a solution of necessity for Hydro. But to suggest that 20 percent, or perhaps any UFOP, relates to the physical dependability of these units is probably wrong.

We note that, even if UFOP had some real meaning for these units, the average UFOP for the last five years (2011-15) is 28 percent[25]. The same logic discussed above for Holyrood is even more applicable here. There is no basis to assume that things are going to get better for these units; quite the contrary, things should be expected to, and are in fact, getting worse. Given a minimum UFOP of 28 percent, and the inherent inadequacy of UFOP in the first place, we have continuing concern that these units are undependable from a supply planning perspective.

4. Hardwoods and Stephenville Reliability Conclusions

The following are our conclusions on how the CTs' performance expectations should be included in the ESRA:

- The use of UFOP in the model produces misleading and overly optimistic results. Ignoring forced de-rates for units whose primary forced outage mode is a de-rate, is a fatal flaw.
- There is no basis to assume that future CT performance will be better than, or even equal to, recent (five-year) performance.
  - Hydro's use of a 20 percent UFOP, versus five-year experience of about 28 percent, is therefore inappropriate.
  - Some additional deterioration from recent performance is reasonable to expect, given the age and condition of the units. A figure in excess of 30 percent would be more reasonable but still not suitably reflective of the state of these units.
- Given the condition of the units and no basis for expecting anything better, it may be more appropriate to assume a 50 percent UFOP, thereby counting on only one of the two units for dependable capacity.

[22] "UFOP does not contemplate a de-rating". PUB-NLH-637
[23] PUB-NLH-637
[24] November 2016 ESRA, Appendix A, Page 5
[25] PUB-NLH-636, Page 3

- The current ESRA seriously over-estimates the ability of both Hardwoods and Stephenville to reliably support the system pre-Muskrat Falls.

D. Hydraulic Units

In past years, the hydraulic units have not been especially relevant in the supply adequacy discussion. The units have high reliability and, when compared to the reliability of the thermal units, they tend to fade into the background. Hydro's status review of the plants reveals no major threats at this time.

- The penstock issues at Bay d'Espoir Units 1 and 2 (bad welds) seem to have been resolved, but the exposure is that similar problems may exist at other units. This has not been the case in inspections so far but remains a risk going forward.

- The Paradise River unit (8 MW) suffered from a high number of trips for unknown reasons. The problem seems to have been located and resolved.

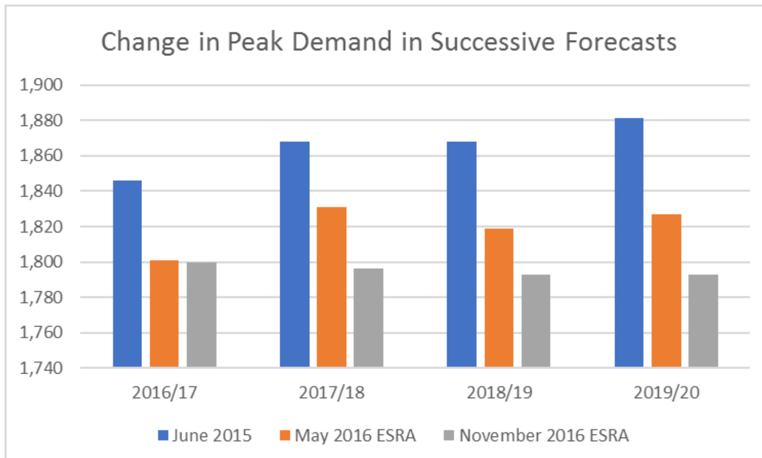
- Frazil ice at hydro units has been an issue in the past and contributed to the supply issues in 2014. Hydro reports that this challenge is being effectively managed.

- Bay d'Espoir Unit 7, Hydro's largest hydraulic unit, has had significant vibration issues. Those issues now seem to be resolved.

III. Load Forecast

Liberty reported concerns in its August report on the changes in the load forecast introduced in the May 2016 ESRA. Our concern was based primarily on the precipitous drop from the previous load forecast as well as the generally pessimistic view presented. The forecast presented in May 2016 represented a drop of about 50 MW from the prior forecast, which was less than a year old. This is an extremely large change by any standard and begs the question of why the reduction.

The subsequent forecast, presented in the November 2016 ESRA, introduced yet another significant reduction in forecasted peak demand. The accompanying chart shows the major drops, all introduced within 18 months of each other. The forecasted demand for 2019/20, which is less than three years away, has dropped by 88 MW. If this evolution is correct, the potential need for any new CT has disappeared in a short time.



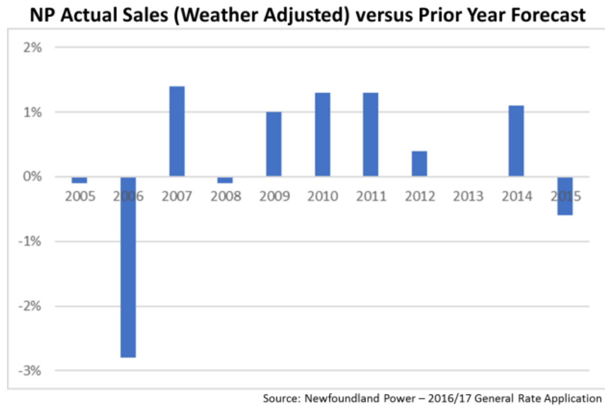
Liberty continues to be concerned that the forecast is overly pessimistic. As a result, we sought to understand the new load forecast in greater detail.

Because much of the reduction has been attributed to Newfoundland Power (NP) customers, we began with a review of the load forecast included in NP's recent rate case. A key driver of that, or any other load forecast, is the predicted economic outlook. It is no secret that the current economy and near-term outlook in the Province is not encouraging. The Conference Board of Canada's Provincial Outlook, Winter 2016, dated February 4, 2016, which is a basis for the NP load forecast, concludes "the outlook for Newfoundland and Labrador is grim".

We do not have similar detail on the updated forecasts, and specifically an update to the Conference Board assessment. This was requested in PUB-NLH-626, but Hydro does not subscribe to the Conference Board service and was unable to provide an updated report.

While very pessimistic, the economic forecast by the Conference Board that we reviewed covered only the near-term (through 2017). Hydro and Newfoundland Power apparently believe that an extension of that negative outlook for several more years to the end of the study period was appropriate. We have no knowledge of whether such an extension is supported by the Conference Board. In any event, the entire study period is now characterized by declining energy and peak demand.

Past NP forecasts have proven slightly pessimistic, although not necessarily to the extent one should make an issue of it. These deviations are for year-ahead forecasts and, of course, one should expect that multi-year forecasts, such as through 2019-20, would be much less accurate. The accompanying chart shows that the year-ahead deviation has been about 1 percent for a number of recent years. Even that becomes very significant if compounded for several years.



Based on (1) the degree of decline in the economic forecast, (2) the extrapolation of the near-term Conference Board view as opposed to a longer-term analysis, (3) the consequences to the Province if the forecast is correct and, to a lesser extent, (4) the recent tendencies to err on the pessimistic side, we believe that all of the risk to the predictions of peak demand are on the upside.

The scenario that emerges from Hydro's forecasts can be characterized as (a) sustained economic weakness for several years, which is then likely to be exacerbated by (b) significantly higher consumer costs from the (at least) doubling of electric rates when Muskrat Falls comes in service.

IV. Other Supply Variables

A. Muskrat Falls Delays

The significant increases and delays to the Muskrat Falls project announced in June 2016 are not relevant to this report, except to the degree they influence the need for new, pre-Muskrat Falls generation.

The current ESRA assumes that Muskrat Falls and the LIL will be at full capacity for the winter of 2020-21. The ESRA therefore limits its analysis of supply adequacy through to the previous winter, 2019-20. The window covered by any near-term supply decision is therefore only the next two winters. That, in itself, might be a powerful argument to decline to add generation. Some might argue, quite logically, that the supply situation in the next two years does not necessarily look to be of extreme risk and there is little time to do much about it anyhow.

This logic assumes that Newfoundland's risk ends after 2019-20, at which time any analysis of the need for more supply shifts to a post-Muskrat Falls set of assumptions.[26] What is the chance that Muskrat Falls is further delayed? Liberty does not have the data necessary to answer such a question. On the other hand, the limited information available to the public, which admittedly can be misleading, seems to suggest that further increases and delays are likely.

Liberty notes that there has been little information on progress versus the planned in-service date. There has been no report from the Oversight Committee since December 2015 and the consultant charged with cost and schedule assessment has not been heard from since April 2016. In the absence of better data, there is little alternative but to assume that supply needs beyond the timeframe of the ESRA are a risk that should be considered.

B. Operational Reliability / Organizational Capabilities

A central concern in every Liberty report has related to the "softer" elements of reliability, specifically, Hydro's operational culture and its organizational skills and capabilities in managing reliability. It is customary to respond to reliability issues with physical improvements: new capacity, new transmission, new relaying, or redundant systems seem to always be the answer. The issues of operational priorities, human contributions, and how the organization is designed to deal with emergencies are too-often ignored, or at least downplayed.

But these soft areas, although harder to cope with, are very often the secret to success, or alternately the root cause of failure. After three years, Liberty is more convinced than ever that the latter (root cause of failure) is indeed the case at Hydro. The evidence grows with every year and with every incident. Time and again we see that failures arise with Hydro's approach.

Liberty is especially concerned that the fundamental, yet all-important notion of utility culture and capabilities has gotten little attention at Hydro. This is even though Hydro suffered outages, equipment damage, and significant prudence-related penalties from these very causes. We

[26] Note that Liberty has concluded that any post-Muskrat Falls need for new capacity is based on system reliability and the need to survive an extended bipole outage, where the pre-Muskrat Falls need is based on adequacy of supply to meet demand.

expanded our discussion in both our analysis of the March 2015 voltage collapse and in our August 2016 Phase II report. These issues have been clearly and frequently communicated, but have unfortunately gathered little response from Hydro. We note that the Board has now ordered Hydro to respond to these concerns by March 30, 2017.

The Province is faced with many electric issues with a potentially great impact on the community. The large investment in Muskrat Falls, new transmission, consideration of new supply needs, and other system improvements are all intended to enhance reliability. It is Liberty's belief that the full benefits of these investments, or any benefit at all from a reliability perspective, will not result if Hydro is unable to responsibly operate, maintain and manage its assets from a reliability perspective. This issue must be given a far higher priority by Hydro.

C. TL-267

TL-267, a new transmission line between Western Avalon and Bay d'Espoir, was first shown as a significant benefit to the supply situation with the May 2016 ESRA. It is our understanding that the line will be in service for next winter (2017-18). Progress should continue to be monitored as delays in this project would have negative effects on reliability. Hydro reports reliability violations in 2017-18 if TL-267 is not in service.[27]

[27] NP-NLH-165

V. Analysis of Hydro's Supply Assessment

We have discussed most of the key assumptions included in the ESRA. In this chapter, we review how Hydro brings these assumptions together and reaches its conclusions and we provide our opinions on the appropriateness of Hydro's conclusions.

A. Hydro's Approach

The Board directed Hydro to prepare a report by November 30, 2016 on a comprehensive review of the supply for the IIS prior to Muskrat Falls. It is well known that such decisions are generally not black and white but rather require a balancing of utility priorities, such as cost, reliability and customer needs. The Board's direction to Hydro required an analysis "that considers all risks" and "provides a risk-based recommendation on the need, timing and amount, for additional supply if any, prior to interconnection".

While Hydro has provided relevant data in the ESRA, it is difficult for the reader to assess the relative degree of risk and uncertainty. Consider for example:

- There is no discussion of the degree of uncertainty and the risk and impact of various parameters being wrong. Such considerations are critical for important parameters such as the reliability of the thermal units, the load forecast, and risks of Muskrat Falls delays.

- The reference cases chosen, which are shown below, provide minimal variation and, for our purposes, can all be considered the same. The notable exception is the expected case, which includes a 110 MW supply addition in the winter of 2018-19. Otherwise, the last year (winter 2019-20) differences in peak demand vary by only 0-13 MW from the expected case.

The Five Reference Cases Studied by Hydro

	Supply	Curtailable Load	Demand
Expected Reference Case	Assumes current supply with 110 MW recall added in 2018-19	Assumes 90 MW	Current P90 load forecast
Fully Stressed Reference Case	Assumes current supply	Assumes 90 MW	Current P90 load forecast
Fully Stressed Reference Case with Sensitivity Load Projection I	Assumes current supply	Assumes 90 MW	Stable demand forecast (<10 MW impact over expected case)
Fully Stressed Reference Case with Sensitivity Load Projection II	Assumes current supply	Assumes 90 MW	Higher industrial coincidence (several added MW above Load Projection I)
Fully Stressed Reference Case with Sensitivity Load Projection III	Assumes current supply	Assumes 90 MW	Less customer demand diversity (several added MW above Load Porjection I)

- Hydro judged supply adequacy on compliance with its selected single criterion – EUE. But the data are presented essentially as "pass-fail".[28] No quantification of EUE is provided,

[28] This is not the case in the reserve margin analysis, where specific quantities are provided in each case.

except in the few limited cases where the criterion of 300 MWh was violated. These violations were 15 and 24 MWh respectively in the current winter for two of the five cases considered. All other years, and all other cases, were "pass".

This pass-fail approach begs the question and should be considered unacceptable. For example, if EUE was instead presented as 290 MWh instead of "no violation", it is very possible that a reasonable decision-maker would consider the many uncertainties in the analysis (including the load forecast, thermal unit availabilities, and further Muskrat Falls delays) and judge that the risks require new supply. But how can such a decision be intelligently made when the results are presented in a way that precludes knowledge of how close to the criteria we are?

Hydro's approach also presumes that (1) there are specific criteria from which a rigid, yes-no response can be crafted to the supply question (in our case, 300 MWh EUE) and that (2) competing priorities that might have to be balanced do not exist. Both presumptions are wrong and oversimplify the supply analysis.

Although Liberty believes that suitable risk analysis should be required in all future supply assessments, and a balancing of cost, reliability risk and customer needs and expectations must be considered, we nevertheless think that the data available now is suitable for decision-making in the immediate case, as recommended in Chapter VI.

B. Capacity Assumptions

Hydro provided a detailed list of assumptions regarding its current supply portfolio and the capacities that it was depending on from each unit.[29] This sums to a capacity of 2,009 MW. That value is used in all cases except for the expected case starting in the winter of 2018-19, when a total supply of 2,119 MW is assumed, due to the addition of 110 MW of recall power. This assumes that (1) the LIL is available and (2) it is technically feasible to transmit the recall power. Hydro has completed a study that certifies the feasibility of transmitting the recall power.[30] Hydro notes however that the commercial arrangements associated with transmission of the recall power remain to be completed.[31]

None of the reference cases include any imports over the ML, although Hydro states otherwise in NP-NLH-156 ("Hydro's ESRA only considered the benefit of import power over the ML in the context of its Expected Case parameters"). On the other hand, the ESRA states that "this analysis [the expected case] considers no import over the ML". Since the supply tables show no entry for such imports, we have assumed the RFI response to be incorrect and have assumed no ML imports for any time or any case in the ESRA.

Capacity assistance in the ESRA is shown as 90 MW, 80 from Corner Brook Pulp and Paper and 9.9 from Newfoundland Power. At the same time, the 2,009 MW of supply includes 10.8 MW of

[29] November 2016 ESRA, Appendix D
[30] PUB-NLH-630
[31] NP-NLH-158

"Vale capacity assistance". Board staff indicates that the following recent changes should be applied:

Reduction in Vale	-3.2
New Praxair	5.0
New Vale	6.0
Total	7.8 MW

This suggests that it may be appropriate to increase reserve margins by about 8 MW. It will also be noted that none of the load data recognizes the 20 MW impact of an emergency voltage reduction.[32]

C. Analysis of Reserve Margins

We have commented frequently in recent years on the use of reserve margins in capacity assessments, including the determination of optimum reserves for Newfoundland. At one time, Hydro might have considered 170 MW adequate, based on N-1 (loss of the largest unit). Hydro has now settled on a minimum target reserve of 240 MW, which is based on the 170 MW N-1 plus an added 70 MW. This equates to a margin of 13.3 percent.

The consideration of a minimum standard for reserve margin is more intuitive than other reliability criteria. We know that the potential for a loss of 240 MW in generation is very real – 233 MW were actually lost in the emergency of January 2014. On the other hand, Hydro had previously functioned with lower values. We would prefer to see 15%+.

Notwithstanding the 240 MW target, Hydro arrives at reserves of about 300 MW and more in all the scenarios considered in this ESRA. These results are far in excess of all previous supply assessments going back as far as early 2014. This is understandable from a capacity perspective in that (1) the new Holyrood CT contributes 123 new MW, (2) the Holyrood black start diesels can contribute about 10 MW to peak needs, and (3) the interruptible load has increased greatly since 2014.

Much of this additional capacity has been offset by changes in Hydro's approach to judging supply needs. These changes include the use of a P90 forecast, which is both conservative and appropriate.

Despite these other changes in the calculation of reserves, the dominant impact on the recent ESRA has by far been the load forecast in terms of expected peak demand. There are many factors that must be analyzed to assure supply adequacy, but it is becoming very clear that the load forecast will be a primary factor influencing the potential need for new capacity in the near-term.

[32] November 30, 2016 ESRA, Page 37, Table 10 footnote

Impact on Reserves of the More Pessimistic Load Forecasts (Expected Reference Case)				
	2016/17	2017/18	2018/19	2019/20
Nov 2016 Forecast	299	304	416	416
June 2015 Forecast	253	232	341	328

Consider the base case, as illustrated in the accompanying table. With the new, pessimistic forecast, the 240 MW target is never threatened. If the June 2015 forecast had been retained, the resulting margin is at about the 240 level, and falling beneath it in the coming winter. The arrival of the recall power over the LIL in the following winter solves that violation.

Impact on Reserves of the More Pessimistic Load Forecasts (Fully Stressed Reference Case)				
	2016/17	2017/18	2018/19	2019/20
Nov 2016 Forecast	299	304	306	306
June 2015 Forecast	253	232	231	218

The fully stressed case considers the possibility that the recall power will not be available when planned. In that case, the 240 MW reserve target is missed for every winter before Muskrat Falls. Our point in providing these comparisons is to highlight the impact of the new forecast.

In conclusion, to the extent the load forecast is appropriate, the resulting reserve margins (300+) are adequate, whether or not the recall power materializes. Note the major contribution here of the recall power in mitigating risk.

D. Analysis of Reliability vs Planning Criteria

Hydro's primary supply planning criterion has been an LOLH of 2.8. More recently, Hydro has focused on EUE with a criterion of 300 MWh, which Hydro estimates is equivalent to an LOLH of 2.8 and a loss of load probability of once in five years. The corresponding criteria for other North American systems will differ by a factor of two. Hydro will likely be required to subscribe to these more conservative criteria once Muskrat Falls is in service and Hydro is connected to the North American grid. In the meantime, it is appropriate to use the more relaxed standards in this assessment.

The most important conclusion in this ESRA is the absence of criteria violations. There are only two violations of 15 and 24 MWh (in the current winter for two of the five cases considered). There was no violation in all other years, and all other cases. This is a very positive result, since the violations were for a winter that is essentially complete and they were of a minimal amount. Hydro did not report values for LOLH in any of the cases.

E. Supply Assessment Conclusions

The overall conclusion and tone of the Hydro assessment amounts to an "all clear" signal regarding new capacity. Going forward, Hydro suggests that studies will be ongoing. For now, however, the question of pre-Muskrat Falls capacity has, in Hydro's mind, been answered. Liberty believes that the many uncertainties and potential inaccuracies in the ESRA demand a closer look at the "all clear" signal.

We discussed above the many uncertainties that have not been subjected to a suitable risk analysis. The uncertainties are not evaluated and the results are presented on an absolute, single-value basis. Areas lacking in this regard include:

- The ESRA is silent on the potential for further Muskrat Falls delays, with the study period ending in 2019-20. Significant delays will increase the likelihood that new capacity is needed, and that might become apparent sooner, rather than later. We have no information to judge either the risk of Muskrat Falls delays or their impact. Both are significant omissions in the ESRA. (See further discussion below).

- The reliability of Holyrood, as reflected in the model with a 14 percent DAFOR, represents an over-optimistic expectation for the units to support the system. We believe that the use of DAFOR, as compared to other measures, offers some degree of conservatism, but (1) the weak recent performance of the units, (2) the likelihood that performance will worsen, and (3) the inability to reflect the chances for catastrophic events in the model, all suggest that the ESRA is counting on Holyrood to a degree not justified by the facts. The ESRA does not discuss any of these uncertainties and the exposures they represent.

- Similarly, the model appears to be taking far too much credit for the Hardwoods and Stephenville units. The use of UFOP, in lieu of a de-rating adjusted variable, is inappropriate. Further, the choice of 20 percent for UFOP significantly overstates the reliability of these units. Again, the ESRA does not discuss any of these uncertainties and the exposures they represent.

- The load forecast is very pessimistic. It would seem likely that any exposure here is to higher peak demand, but any sensitivities presented are minimal.

On the other hand, there are several areas in which the ESRA is conservative, which may offset some of the inaccuracies suggested above:

- The ability to access the 110 MW recall power in 2018 is a major contributor in relieving the potential need for new capacity.

- The use of a P90 forecast is a big improvement and adds conservatism.

- A load reduction of 20 MW for an emergency voltage reduction is not included, but this represents "capacity" which is available and likely to be used in a supply emergency.

- Additional interruptible load of about 8 MW is likely and has not been included in the ESRA.

None of these considerations, or lack of consideration, dictate a distinct answer to the supply question. Rather a rational balancing of these factors against each other must be undertaken. We do so in the next chapter.

VI. Liberty's Analysis and Recommendations

The need for new capacity in terms of its amount and timing is rarely a black and white decision. Hydro has presented a case for why new pre-Muskrat Falls capacity should not be acquired. We have been critical of many of Hydro's estimates, approaches and results, as detailed in prior chapters. In this chapter, we bring all of the issues together and provide a recommended solution to the pre-Muskrat Falls supply question.

A. Analysis of Risks and Uncertainties

The fact that the ESRA has many significant risks and uncertainties is not a criticism but rather an inherent part of the analysis. A good analysis will communicate the nature of those risks and uncertainties and seek to describe where on the risk spectrum they fall. When a recommendation is made, the reader should have some understanding of the author's level of confidence; i.e., is the recommendation and its underlying assumptions conservative, optimistic or expected (50-50). When dealing with high levels of uncertainty, there is no right or wrong answer but only the relative chances for each of the possible outcomes.

In this section, we:

- Define the risks and uncertainties embedded in Hydro's analysis.
- Assess the degree, if any, to which those risks might cause us to challenge Hydro's "no new capacity" conclusion.
- Introduce considerations that were not addressed in Hydro's analysis.

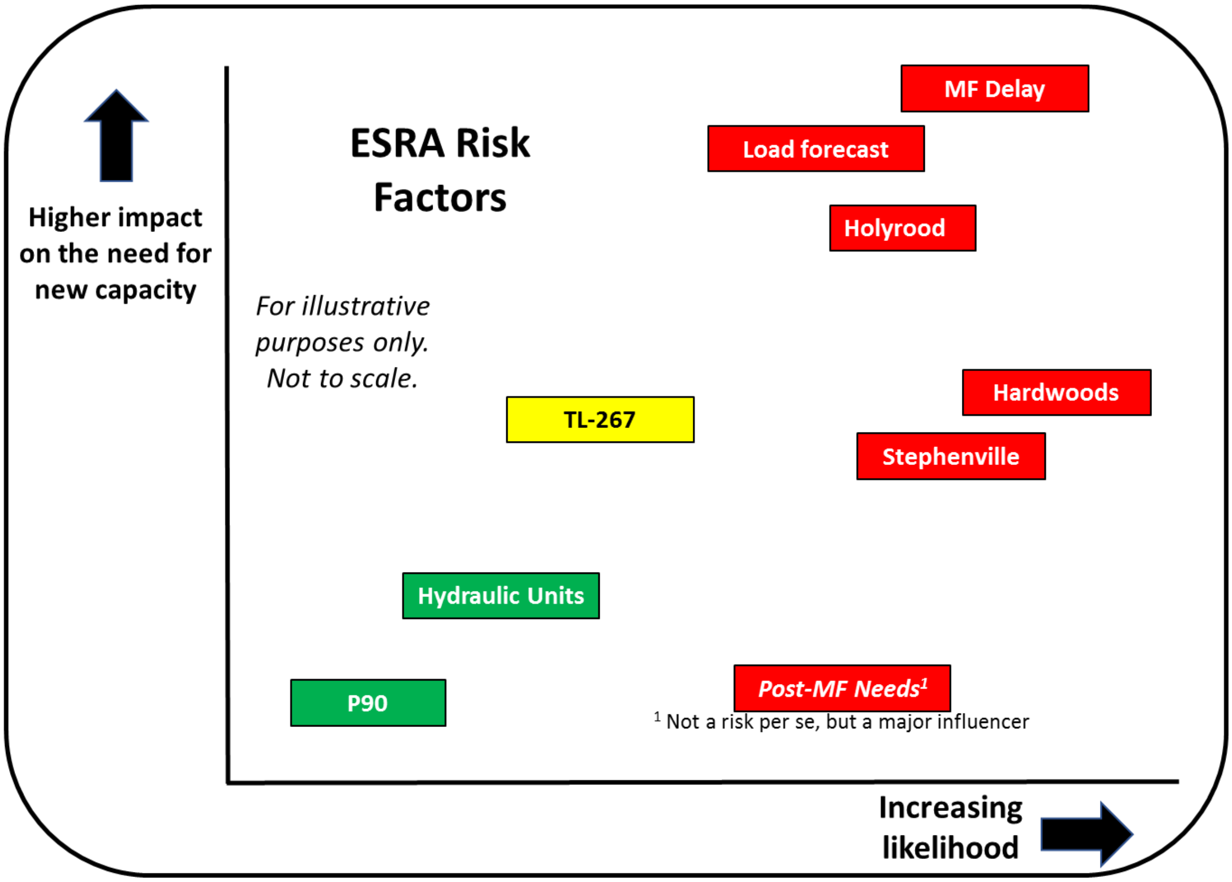
1. Defining Risks

In reviewing the ESRA, there are a number of risk-areas that must be considered and we have already discussed many of the areas with which we disagree. To summarize, the following risks are worthy of study:

- Generation reliability
  - Holyrood performance will be worse than estimated
  - Hardwoods performance will be worse than estimated
  - Stephenville performance will be worse than estimated
  - Hydraulic unit performance will be worse than estimated
- Load forecast
  - Economy and load growth will be better than estimated
  - P90 forecast is not sufficiently conservative
- Muskrat Falls will be delayed
- TL-267 will be delayed.

In addition, there is a ninth area of concern that is not a "risk", but rather a factor that is likely to greatly influence the pre-Muskrat Falls decision. That factor is the potential need for post-Muskrat Falls supply. Such a need will not influence the pre-Muskrat Falls need, but it will greatly influence the pre-Muskrat Falls affordability.

Liberty considered each of these nine factors and assigned our opinion of the likelihood and consequences of each. The diagram below illustrates our opinions in a simplified way. This is a highly subjective assessment based on our research and many discussions with Hydro and others.



2. Minimal Risk Factors

The diagram suggests that we focus on the factors in the upper right, which means both higher probability of occurrence and a higher impact on the decision for new capacity. We dismiss the following:

- Hydraulic units: Hydro's hydraulic units have historically performed well, notwithstanding the recent issues discussed above. Their DAFORs are very low. The recent issues may raise some concern about growing risk, but we believe such risks are minimal.

- P90: The use of a P90 forecast, compared to P50 or similar, is conservative. By definition, the risk of exceedance is small (10 percent). In this case, the bulk of the uncertainty lies in a favorable direction and hence the risk-related influence can be ignored for this discussion.

- TL-267: This new transmission line is expected to produce significant benefits in terms of system reliability and it is a real factor in the Hydro analysis. Delays to the line will increase EUE, so there is risk here. On the other hand, we have no indication that the in-service date for the coming winter is threatened. Also, any delays are likely to impact only the coming winter, such that there is little to be done in the way of mitigation if TL-267 is delayed.

3. Major Risk Factors

We have discussed many of the six remaining risk areas earlier. Here, we summarize our conclusions and comment on the relative chances for these risks materializing and the potential impacts on the supply decision.

a. Muskrat Falls Delays

We have, somewhat arbitrarily, settled on two years as being the amount of a delay that would heavily influence the supply decision. We have noted that delays have already been announced, and we believe the project is vulnerable to further schedule problems. A delay of two years or more is possible.

A delay of two years will mean that no new capacity will be available until the winter of 2022-23. This provides two additional years of deterioration of the thermal assets and increases the chance that the economy / load forecast will recover. In addition, there may be even further Muskrat Falls delays. None of this would require an accelerated response, but it would make sense to begin the planning process for a new CT.

We acknowledge that we are susceptible to criticism for speculating on the Muskrat Falls schedule in the absence of hard data. But the lack of hard data is in fact one of the major reasons for our schedule concerns. We do not subscribe to the "no news is good news" philosophy, especially for large construction projects. And the lack of visibility amplifies these concerns.

There is a wide range of potential outcomes for the in-service date of Muskrat Falls and prudent decision-makers must gauge the risks of those various outcomes. Hopefully, new and better information will become available. In the meantime, pessimism is likely to prevail, and rightly so.

Potential impact on supply decision: The planned availability of the recall power in 2018 is a significant mitigating factor here. A Muskrat Falls delay presents opportunity for thermal unit performance to decline and load growth to go up, both major risks. If the 110 MW recall power is available, and we assume it is, the delay issue is less threatening. We will then be in a mode of waiting to see if the declining thermal reliability and increasing load growth (if they happen) can catch up to and surpass that 110 MW before Muskrat Falls is in service (presumably 2022-23). If the recall power becomes in doubt, all bets are off and the Muskrat Falls delays rise to the highest threat level.

b. Load Forecast

We noted earlier the severe consequences to Newfoundland if the load forecast, or more precisely the economic factors dictating the load forecast, are correct. The one-two punch of (1) many years of economic malaise followed by (2) a drastic increase in customer costs in the form of an at least doubling of electric rates with the interconnection with Muskrat Falls, can be a tragic outcome. If one could be confident that the pessimistic economic forecast is correct, then we can assume two things:

- Peak demand will stay the same or decline, creating no new needs for capacity.
- Customers probably will not be well positioned to support higher costs for new generation, even if it were needed.

This case could influence the consideration of new supply indefinitely. The direction of the economy and load over the next few years should be re-examined periodically. We suspect that the chances of the peak demand forecast being too low are greater than it being too high.

Potential impact on supply decision: The impact of an overly pessimistic load forecast is perhaps best reflected in the analysis of reserve margins above. Recall that a reversion to the 2015 load forecasts violates the 240 MW reserve target for next winter only. This impact is mitigated somewhat by (1) the one-year nature of the violation, (2) the limited magnitude of the violation and (3) most importantly, the unlikelihood that the forecast will be off by such a large amount in the next year. After next winter, the 110 MW recall power neutralizes the risk.

The saving nature of the recall power suggests that errors in the load forecast will not become a major factor in the next year or two but are more likely to threaten after that. The threat may become especially significant if merged with the Muskrat Falls delay scenario, both of which are real risks.

c. Holyrood Reliability

We have suggested that the use of DAFOR in Hydro's model to measure the probability that Holyrood will be available is conservative. We are critical of Hydro's selection of 14 percent as a value for DAFOR. Recent data and the deteriorating trend of the units suggests a much higher value. In addition, the risks of catastrophic failures, which cannot be meaningfully represented in the model, are real, having appeared three times in the last four years. The conservatism of DAFOR tempers our pessimism, but we nonetheless remain concerned that Holyrood is a major exposure area and is likely to get worse, not better, in the years ahead. The expectation that Hydro can survive five more winters at Holyrood without a significant event, as opposed to all more routine forced outages, is probably unreasonable.

Potential impact on supply decision: The prior ESRA included reliability violations when the Holyrood DAFOR was assumed to be 19 percent. This does not mean that this ESRA, with its lower peak demands, would produce the same result. Further, since we think the model's use of DAFOR may be conservative, the typical forced outage risk is becoming less of a threat. This may be statistically logical, but it fails the common-sense test. We need to be especially concerned about the types of outages that are debilitating to the system. In the case of Holyrood these would be extended unit outages where about 170 MW would be lost for most of the winter or multi-unit outages where 300 or more MW could be lost. Experience of the last few years suggests a high probability of one or more such events before Muskrat Falls is in service, with a good chance of producing customer outages.

d. Hardwoods and Stephenville

We have assigned a slightly higher risk to Hardwoods, simply on the basis of the failure to understand the last engine failure. This is splitting hairs to some extent, however, since both units are very high risk. Their negative impact on system operating risks is limited only by (1) their size, (2) the tendency for outages to be of one end only, and (3) the availability of a spare loaner engine, all of which represent legitimate mitigation of risk.

The outage patterns of recent years have been all too obvious in the case of these two units. We do not fault Hydro's efforts to improve, maintain and, when necessary, repair the units. Nevertheless, at some point, this no longer becomes practical. The decline in the condition of these CTs, which started from a weak position to begin with, argues that their remaining life is limited, and that limit is much sooner than the mid-2020s now envisioned by Hydro. One would think that at some point one or more new CTs will be needed for no other reason than to replace Hardwoods and Stephenville.

If the units do survive, it will surely be with higher UFOPs than predicted by Hydro. In addition, UFOP is a poor indicator for these units in any event, and seriously overstates the probability that the units will be available. The bottom line is that these units are destined for a low and perhaps declining reliability for the remainder of their lives. Hydro's portrayal of their reliability in the model is greatly over-stated.

Potential impact on the supply decision: The risk of one or both of these CTs being unavailable when needed is high. We would not recommend counting on more than one of them in the model. This would amount to losing 50 MW of capacity, or 25 MW on a de-rate. This is probably not enough to warrant a great deal of expenditure in the near term, but the demise of these units is inevitable. It is very likely they will have to be replaced, and likely sooner than later.

e. Post-Muskrat Falls Supply Needs

If new capacity is needed some time during the first few years of Muskrat Falls operation, then any new pre-Muskrat Falls supply is simply an advancement of that generation by a few years. This logic fails, of course, if the post-Muskrat Falls generation could be provided by the ML. The feasibility of that solution has yet to be demonstrated.

In our Phase Two final report, we discussed our concerns for post-Muskrat Falls IIS reliability, and specifically the exposure to extended (days or weeks) shedding of customer load. The need to shed load to accommodate a trip of the LIL under certain load conditions, including high winter season loads, sets the stage for this problem. Given sufficient backup, the duration of resulting outages can be minimized, but if sufficient reserves are lacking, sustained rotating outages may be necessary. The combination of an extended LIL outage (perhaps from tower failures) and insufficient reserves to limit the event duration should be considered unacceptable.

Hydro has not responded to Liberty's concerns on post-Muskrat Falls needs and reliability, and perhaps Hydro will identify alternate solutions. Until then, Liberty believes that the need for post-Muskrat Falls capacity is valid and should be considered a major, and perhaps a deciding, influence in the pre-Muskrat Falls supply question. Liberty's concerns would be eliminated here if (1) there is no strong need for post-Muskrat Falls capacity or (2) an alternate source of post-Muskrat Falls capacity, such as the ML, can be identified.

Potential impact on the supply decision: The singular impact on the supply decision is to significantly reduce the cost of pre-Muskrat Falls supply. If the money must be spent in any event, the incremental cost to advance the unit will be small.

f. Putting the Major Risks in Perspective

We are unable to quantify the impact, or sensitivity, of the major risks. That will take an analysis by Hydro of how EUE changes with varying assumptions for the major risks. Such analyses should be a requirement in future ESRAs.

The need to analyze sensitivities should be obvious, given that we are critical of Hydro's major assumptions, yet our subjective analysis tends to downplay the impacts. This demonstrates that the danger of individual risk is perhaps less than we think, but the combination of risks may be another story. In any event, a better understanding of the impacts from combining the risks, which requires a more sophisticated analysis, should be required in future supply risk assessments.

B. Recommended Supply Strategy

The risks and uncertainties in Hydro's ESRA are substantial, and most of them are likely to result in a greater need for more pre-Muskrat Falls capacity. But there are very convincing arguments for not acting on those risks now:

- The likelihood that 110 MW of recall power will be available in the winter of 2019-20 is a deal-changer, providing there is a level of confidence that supply will be adequate, even if some of the exposures materialize.

- The uncertainties in the Hydro analysis suggest exposure to, but not a high probability of, a need for pre-Muskrat Falls supply.

We therefore conclude that:

- There is insufficient justification to proceed with new pre-Muskrat Falls capacity now, and any additional risk of supply interruptions, such as those suggested by our analysis, should be accepted.

- The question should be revisited in one year, or when major assumptions change.

Liberty also believes that, should this recommendation prove to be wrong, there are natural risk mitigations that will allow minimal impact:

- There is ample time for warning if some of the major risks begin to materialize, including the risks associated with Muskrat Falls delays and load forecast errors.

- The need for post-Muskrat Falls capacity will likely be decided in the next year, and that might change the pre-Muskrat Falls cost-benefit equation. The pre-Muskrat Falls decision can be revisited at that time if appropriate.

- If major risk factors begin to materialize but remain uncertain, the CT planning process, including siting, sizing and potential timing, could be started without making any major procurement or construction commitments.

Major unit outages are of course a risk and they can lead directly to system interruptions. This is the added risk that we recommend accepting. Acceptance of that risk is prudent given that:

- Such events can happen even before the new supply can be installed.
- The benefits of new capacity may be of a limited timeframe; i.e., until Muskrat Falls is in service, if it is determined that additional capacity is not needed post Muskrat Falls.

C. What Has Changed

The strategy recommended is at odds with the vulnerabilities and concerns expressed in our August 2016 Phase Two report. The circumstances that lead to such a significant change of opinion include:

- The addition of the 110 MW recall power, which was not included in the earlier ESRA, equates to the addition of a new CT. In that sense, our recommendation for new pre-Muskrat Falls supply has already been fulfilled. This assumes that all technical requirements and commercial arrangements are in place for the recall power.

- A major driver of the supply concerns was the early 2016 problems with the thermal units, the most serious of which was the de-ratings and heightened DAFORs at Holyrood. The AMEC report reduced the severity of the outlook for the reliability of these units.

- The load forecast that accompanied the November ESRA included another precipitous drop in forecasted peak demand.

With these new assumptions, the pre-Muskrat Falls supply picture has changed for the better.

D. Recommendations

The following are the recommendations that flow from Liberty's analysis:

Pre-Muskrat Falls Supply Needs

1. New pre-Muskrat Falls supply should not be pursued further at this time.

2. The need for pre-Muskrat Falls supply should be reconsidered in one year, or sooner, if major assumptions change, including but not limited to:
   - The feasibility of the recall power
   - The load forecast
   - Muskrat Falls delays

3. If a new CT is determined to be a post-Muskrat Falls supply need, the desirability of advancing that CT into the pre-Muskrat Falls window should be evaluated.

Managing Risk Factors

4. Hydro should continue its aggressive efforts to improve Holyrood reliability and should add initiatives aimed at lowering the risk of catastrophic events, such as extended outages or multi-unit failures.

5. Hydro should develop a "replacement plan" for the Hardwoods and Stephenville units with a recommendation for when the units will be retired.

6. Hydro should avoid significant investments in Hardwoods or Stephenville under the assumption that meaningful reliability improvements are not practical.

7. Hydro should promptly report to the Board in the event that the in-service date of TL-267 is in jeopardy, such report to include the effect on supply risks for the next pending winter.

Current ESRA Modifications

8. Hydro should provide the Board a brief report[33] on the effects of the following perturbations on EUE, expressed numerically as opposed to "pass-fail":
   - Holyrood DAFOR = 20%
   - CT UFOP = 30% and a case for 50%
   - 50 MW variation in 2019-20 peak demand versus the forecast
   - Two-year delay in Muskrat Falls

9. Hydro should clarify, or alternately eliminate, its assumptions for Holyrood outages "in the operating season".

10. Hydro or Newfoundland Power should provide:
    a) Any Conference Board outlooks after 2016, including any that form the basis for the current load forecast
    b) Hydro and NP's basis for extrapolating the Conference Board's conclusions to the end of the study period
    c) Any Conference Board information available on the economic outlook beyond 2017

[33] The intention is for a brief understanding of sensitivity and not a definitive analysis of these options.

Future ESRA Modifications

11. Hydro should include a more thorough analysis of risks and uncertainties in future ESRAs, specifically addressing the degree of uncertainty in variables and conclusions as well as the risk those uncertainties produce.

12. Hydro should include a balancing of priorities in future ESRAs, such as cost versus reliability, incremental reliability benefits and cost benefit analysis.

13. Hydro's focus on EUE as the primary indicator of supply adequacy is acceptable; however, reports should also provide some indication of impact on LOLP and, if Hydro continues its use, LOLH.

14. Hydro should investigate the degree to which the potential for catastrophic events at Holyrood (extended outages or multi-unit failures) can be reflected in the model.

15. Hydro should investigate the use of a demand-related reliability measure (DAUFOP) rather than DAFOR for Holyrood in that the plant is not base load and the demand period performance is all-important.

16. Hydro should drop the use of UFOP for the CTs as inadequate and inaccurate and seek an alternate measure (such as DAUFOP).