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October 14, 2016

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Via Electronic Mail and Courier

Newfoundland and Labrador Board
of Commissioners of Public Utilities
120 Torbay Road
P.O. Box 21040
St. John's, NL A1A 5B2

Attention: Ms. G. Cheryl Blundon, Director of Corporate Services and Board Secretary

Dear Ms. Blundon:

Re: Supply Issues and Power Outages Investigation and Hearing - Phase 2 Review - Expert Evidence filed on behalf of the Island Industrial Customer Group

Please find enclosed the original and 12 copies of the Expert Evidence of InterGroup, filed on behalf of the Island Industrial Customer Group.

We trust you will find the enclosed to be in order.

Yours truly,

Stewart McKelvey

Paul L. Coxworthy

PLC/kmcd

Enclosure
c. Tracey L. Pennell, Senior Counsel, Regulatory, Newfoundland and Labrador Hydro
Geoffrey P. Young, Senior Legal Counsel, Newfoundland and Labrador Hydro
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EXPERT REPORT

IN REGARD TO PHASE 2 OF INVESTIGATION AND HEARING INTO SUPPLY ISSUES AND POWER OUTAGES ON THE ISLAND INTERCONNECTED SYSTEM

Submitted to:

The Board of Commissioners of Public Utilities

on behalf of

Island Industrial Customers Group

Prepared by:

InterGroup Consultants Ltd.

500-280 Smith Street

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October 14, 2016

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1.0 INTRODUCTION

This pre-filed expert report has been prepared for two Island Interconnected Industrial Customers (known collectively as the "IIC Group")[1] of Newfoundland and Labrador Hydro ("Hydro" or "NLH") by InterGroup Consultants Ltd. ("InterGroup") under the direction of Mr. J. Osler with the support of Mr. H. Najmidinov. It is evidence in the matter of Phase 2 of the Investigation and Hearing into Supply Issues and Power Outages on the Island Interconnected System ("Phase 2 Hearing") by the Board of Commissioners of Public Utilities ("Board" or "PUB").

Mr. Osler's qualifications are set out in Appendix A. Mr. Najmidinov's qualifications are set out in Appendix B. InterGroup was retained to assist in the review of filing materials based on InterGroup's previous experience with Hydro rate review processes and familiarity with areas of interest to Industrial Customers generally, and to the IIC Group in particular.

Parts of the following information were reviewed in preparation for this testimony:

- Hydro's Energy Supply Risk Assessment ("ESRA") report filed with the Board on May 27, 2016;
- Probabilistic Based Transmission Reliability Summary Report prepared by Teshmont Consultants LP ("Teshmont Report") filed with the Board on May 27, 2016, including the summary report filed by Hydro;
- Power Supply Adequacy and Reliability Prior to and Post Muskrat Falls Final Report filed by The Liberty Consulting Group ("Liberty Report"); and
- Request for Information (RFI) responses from Hydro and Liberty Consulting Group to the requests of the IIC Group and other intervenors.
- Various regulatory filings from the PUB's website including, to a limited extent, the Phase 1 review, Hydro's annual Capital Budget filings and other publicly available documents referenced in this pre-filed expert report.

1.1 OVERVIEW OF ISLAND INDUSTRIAL CUSTOMERS

The IIC Group is comprised of two large industrial customers who comprise almost half of the overall industrial class of customers on Hydro's Island Interconnected System ("industrial class" or "IC"). These companies are:

- Corner Brook Pulp and Paper Limited ("CBPP"); and
- NARL Refining Limited Partnership ("NARL").

[1] This evidence refers to all industrial customers in Island Interconnected system as Industrial Customers, or IC.

The members of the IIC Group are large energy consumers. As Industrial Customers, they generally operate with high load factors (i.e., they have relatively comparable levels of energy use throughout the day and throughout the year), use energy based on Power on Order[2] (identified before the calendar year starts), and typically stay within those forecast limits.

The customers that comprise the IIC Group have a 2017 forecast of 270 GW.h of firm electricity[3] (approximately 4% of the total firm energy or about half of the total industrial customer load delivered by Hydro to the Island Interconnected system). CBPP also consumes energy generation by its own generation sources, and also provides capacity assistance to Island Interconnected System ("IIS") when required based on contract with Hydro.

Industrial Customers' concerns are normally focused around the following:

- Long-term stability and reliability of power supply for all customers in IIS; and
- Lowest cost for power that can be achieved.

The specific concerns of the IIC Group reflect their capital investments in Newfoundland and Labrador, the long-term perspective essential to such investments, and the major stake that a customer with these investments typically has in continued large-scale reliable power purchases from Hydro.

1.2 SUMMARY OF ISSUES FOR THIS PROCEEDING AND PROCESS TO DATE

In January 2013,[4] a series of events produced Island-wide, extensive customer outages, primarily on the Avalon Peninsula, the largest load centre of IIS.

The following additional outage events occurred on Hydro's system between January 2nd and 8th, 2014:

- First, a shortage in Hydro generating resources caused a series of rotating outages; and
- Second, as Hydro and Newfoundland Power were recovering from the circumstances leading up to the outages, a series of equipment and operations issues led to additional outages [i.e., major failures included the Sunnyside transformer, Sunnyside bus protection, Holyrood switching, and the Western Avalon transformer].

This second series of events resulted in widespread, uncontrolled outages as well as another series of rotating outages with significant customer interruptions.[5]

The Board initiated an investigation into the circumstances leading up to and surrounding the outages and retained Liberty Consulting Group ("Liberty") to assist with the investigation. The Board proceeded with a two phase review, with Phase 1 focused on immediate adequacy and reliability issues of the IIS up to the

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[2] The amount of power contracted and to be delivered by Hydro to an industrial customer.
[3] IC-NLH-003, Attachment 1, Hydro`s 2016 Interim Industrial Rates Application.
[4] Liberty April 24, 2014 Interim Report page 1.
[5] Liberty April 24, 2014 Interim Report page 56, Illustration 3.7. On the first day of the outages there were up to 30,000 customer interruptions; on January 4th there were up to 180,000 customer interruptions, on January 5-6th there were up to 100,000 interruptions and on January 8 there were up to 30,000 interruptions.

interconnection with Muskrat Falls and Phase 2 was expected to focus on the implications of the interconnection with Muskrat Falls on the IIS. While it was expected that the issue of the adequacy and reliability of supply on the IIS until interconnection with the Muskrat Falls generating facility would be concluded as a part of the Phase 1 review, the issue continued to be a concern and was included for consideration in the Phase 2 investigation.[6]

As part of the Phase 1 Review Liberty, filed an interim report (April 24, 2014) which included 46 specific recommendations and priority actions to be undertaken in the immediate near term by Hydro and Newfoundland Power to reduce the risks of future outages and improve reliability of the system[7]. On December 17, 2014 Liberty filed two Phase 1 reports, one related to Hydro and another related to Newfoundland Power. The interim and final reports included the following key conclusions that are relevant to the current review:[8]

- The January 2014 outages stemmed from: (a) the insufficiency of generating resources to meet customer demands; and (b) issues with the operation of key transmission system equipment, and a continuing and unacceptably high risk of outages from such causes remains for the 2015-2017 winter seasons [until Muskrat Falls and the Labrador-Island Link come into service].

- Even with the installation of a new combustion turbine and new capacity assistance arrangements with certain industrial customers, generation reserves are very low and the risk of outages remains high for the 2015-2017 winter seasons. It was recommended that Hydro continue to focus on ensuring the availability of all generation units for the winter period.

The Board's Phase 1 Report criticized Hydro for the widespread outages and for failing to fulfill its "obligation to provide an adequate and reliable supply of power to customers."[9] The report also noted that despite the work undertaken since the January 2014 outages, there continued to be notable risks to the adequacy and reliability of supply on the IIS, with ongoing concerns relating primarily to Hydro's transmission asset management execution, operating culture, generation planning and supply, and generation asset management.[10]

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[6] The Board's September 29, 2016 Final Report in the matter of Phase 1 review of Supply Issues and Power Outages on the IIS, Executive Summary, page i.

[7] This included issues related to load forecasting, generation capacity planning, generation and transmission availability, asset management, customer service, and inter-utility coordination. The interim report also highlighted the key conclusions on causes of the outages.

[8] Liberty December 17, 2014 Final Report, pages ES-1 and 3.

[9] The Board's September 29, 2016 Final Report in the matter of Phase 1 review of Supply Issues and Power Outages on the IIS, Executive Summary, page i.

[10] The Board's September 29, 2016 Final Report in the matter of Phase 1 review of Supply Issues and Power Outages on the IIS, page 55.

2.0 SUMMARY OF INTERGROUP CONCLUSIONS AND RECOMMENDATIONS

A summary of the conclusions and recommendations contained in this report are included below.

- **Reasonableness of Load Forecast**
    - It is recommended that Hydro revisit the near term peak load forecast (using P90 forecast as recommended by Liberty). Using a more extreme weather peak forecast case (P90 peak forecast standard as recommended by Liberty), appears appropriate given the unique and isolated nature of the IIS prior to any interconnection support. Hydro may choose to revisit this standard after Muskrat Falls is in service and there is a record of its reliability as a supply source.
    - Hydro should assess the capacity-related risks that would arise from a sudden increase in the demand by IIS customers.
    - It is recommended that Hydro and Newfoundland Power review the reasonableness of the Newfoundland Power load forecast for winter 2016/17 as well as forecast for near future years. In the current circumstances, more frequent load forecast exchanges between Newfoundland Power and Hydro would be beneficial to the IIS.
    - Hydro work with industrial customers who are ramping up operation activities to determine any future increases are expected for these customers.
- **System Planning and Operating Criteria**
    - It is recommended that Hydro be directed to assess its reliability standards given that the isolated nature of the IIS grid pre-interconnection which require more stringent criteria compared to utilities with available access to external power sources at the time of emergency. These reliability standards need to be appropriate after interconnection and during post-Muskrat Falls conditions.
- **Reliability of the Existing System**
    - The record to date indicates that maintaining existing thermal assets and capacity assistance/ load curtailment arrangements with large industrial customers are the key near term options available to mitigate the risk of system disruptions both pre- and post-Muskrat Falls conditions.
    - Though there are clear reliability issues with the existing thermal assets (Holyrood, Stephenville and Hardwoods), there are no immediate alternatives available that can replace these capacity options, and they play an important role in IIS reliability at the current isolated nature. Therefore, Hydro should continue to maintain Holyrood as a reliable energy supply source, but in a cost effective way to reduce adverse cost impacts to customers.
    - It is recommended that Hydro undertake a detailed review of the Stephenville and Hardwoods units as part of any review of supply needs and make recommendations to the Board regarding their future status. Although these plants are costly to Hydro and its customers, there is no immediate alternative available that can replace these capacity

options. Consequently, the plants should be maintained until a new alternative option is available.

- Capacity assistance/interruptible load arrangements provide benefits to utility, participants and IIS customers in both the pre and post-Muskrat Falls environments. Hydro should continue to be encouraged to investigate for additional sources while seeking ways to avoid and/or mitigate system reliability concerns. Participation in capacity assistance and/or interruptible load arrangements require customers to make material investment decisions. Hydro should consider longer term contracts and incentive payments for the risk assumed for each interruption, as well as the impacts associated with reductions or breaks in operations as a result of providing capacity assistance.
- While the impact from conservation demand management may be small, it still can provide benefits to the system, especially in a pre-Muskrat Falls environment. Therefore, continued efforts in this regard should be encouraged.
- Hydro should review supply options available from the existing IIS capacities (including impact from capacity assistance and curtailable loads), through the Maritime Link and Labrador-Island Link after connections and evaluate the degree to which new capacity is required.
- New capacity would add significant benefits to system reliability – however, it will not solve the near term issues as it could take two or more years for construction and commissioning of new thermal generating units. There are also concerns related to the costs for new standby generation that would need to be recovered from ratepayers.

- **Reliability of the ML and LIL**
  - Use of the LIL to help mitigate IIS reliability concerns is limited to the period of time immediately preceding MF in-service when firm recall power is available from Churchill Falls to meet IIS load requirements.
  - The Maritime Link (ML) has the opportunity to help mitigate both pre and post-Muskrat Falls reliability concerns on the IIS.
  - Hydro should be encouraged to firm up the availability of capacity from Nova Scotia (Maritime Link) and through the LIL pre-Muskrat Falls to ensure that these new supply options are readily available.
  - Hydro should be directed to complete the studies identified in the Liberty August 19, 2016 report to ensure that the mitigation options identified by Hydro effectively address identified system reliability concerns. These studies include determining of the capacity availability from Nova Scotia, the anticipated terms and pricing, confirming the availability of capacity to the IIS through the LIL pre-Muskrat Falls, and completing system integration studies highlighted in the Liberty Report.

3.0 REASONABLENESS OF LOAD FORECAST

The load forecast is one of the critical variables that may impact the adequacy of capacity planning. Specifically, during the Phase 1 Review, Liberty highlighted that unexpected increases in actual peak demand compared to forecast adversely impacted Hydro's ability to response in a supply emergency.[11]

The process to date has raised two separate issues regarding the reasonableness of the peak demand forecast used by Hydro for system planning:

1. **Reliance on Less Stringent (P50) Peak Demand Forecast as Base Case for Capacity Planning:** There is a question as to whether the method used by Hydro to determine the adequacy of planned capacity for the IIS is not sufficiently robust, and whether the P50 peak demand forecast may indicate higher reserve levels for capacity than may actually be the case. If a more stringent criteria was used, the requirements for available capacity would be higher.

2. **Reduction in Hydro's near term Load Forecast:** The most recent near term load forecast provided by Hydro in the ESRA, and used to determine the adequacy of capacity for the IIS, includes a material reduction in peak demand compared to the forecast prepared in the previous year. To the extent that the actual peak demand is higher than the reduced forecast used in this assessment – it raises concerns regarding the adequacy of the capacity planned for the system.

Each of these issues are discussed further below.

Use of Less Stringent Capacity Criteria Forecast Method

The Liberty Report indicates that use of a low load forecast as the base case for capacity planning (i.e., the P50 peak demand forecast) contributed to the supply shortage issues in 2014.[12] Liberty's interim report notes that while it may be reasonable for most utilities to use a P50 peak demand forecast for system planning, this type of low load forecast may not be acceptable for planning on the IIS. Liberty also expresses concern that unexpected increases in actual peak demand compared to the base case (P50) forecast may adversely impact Hydro's ability to respond in a supply emergency.

In response to the concerns raised, Hydro in the ESRA developed and used both a base case forecast (the P50 peak demand forecast), as well as various sensitivities, including an extreme worst case scenario (the P90 peak demand forecast) in its assessment of IIS capacity requirements.[13]

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[11] Liberty December 17, 2014 Final Report, page 14.

[12] On page 11 of December 17, 2014 Final report Liberty again highlighted that the low load forecast (i.e. using P50) was one of the factors that contributed to the supply shortage.

[13] Hydro in determining its peak load forecast uses historical weather based on 30 years of wind-chill data, selecting the worst day for each year. The average of these 30 worst day data points would be taken as the basis for the peak load forecast. When P50 is used, there is a 50% chance that the actual may exceed [or may be lower than] the forecast which is based on the average of 30 data points. When P90 is used, the chance of actual peak being lower than the forecast would increase to 90%, i.e. forecast peak is based on assumption that the weather for coming forecast year would be similar top 10% of "bad weather" and only 10% of those 30 data points are higher than the forecast peak.

- Under the P50 peak demand forecast, there is a 50% chance that the actual peak load in a given winter will exceed the forecast peak.
- Under a P90 forecast the peak forecast used is higher, and therefore the requirements for available capacity are also higher. Going forward this would reduce the risk of outages related to generation supply shortages.

Hydro indicates that under both the P50 and P90 peak load forecast it can avoid, or reasonably mitigate, the risk of unserved energy on the IIS.[14] Liberty in its report recognizes as positive the use of the P90 forecast as a sensitivity case, but asserts that the P90 forecast should replace the P50 forecast as the base case forecast used to determine peak load forecast requirements.[15]

Table 3-1 below provides a comparison of the P50 and P90 peak forecasts. The table shows that the difference in the two peak load forecasts are in the range of 67-73 MW (an approximate 4% difference between the two approaches).

Table 3-1: Comparison of P50 and P90 Peak Forecasts[16]

	P50, MW	P90, MW	Diff., MW	Diff. %
Winter 2016/17	1,733	1,801	68	4%
Winter 2017/18	1,758	1,831	73	4%
Winter 2018/19	1,752	1,819	67	4%
Winter 2019/20	1,760	1,827	67	4%

The IIS is currently an isolated system and in case of high peak demand Hydro is not able to import any supplemental energy from outside the IIS. Prior to interconnection using a case that incorporates a more extreme weather peak forecast would provide a more conservative assessment of available capacity and would be more appropriate. As such, application of a P90 peak forecast standard for the IIS, as recommended by Liberty, appears appropriate given the unique and isolated nature of the IIS prior to any interconnection support. Hydro may choose to revisit the use of this standard after Muskrat Falls is in service and there is a record of its reliability as a supply source.

Reduction in Load Forecast used to Determine Capacity Requirements

Table 3-2 below provides the peak forecasts provided by Hydro in the ESRA (forecasts as of April 2016). As indicated in Table 3-2, the updated (2016) forecasts are 37-54 MW lower than the June 2015 forecasts prepared by Hydro.

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[14] ESRA, page 29.
[15] Page 12 of Liberty's April 24, 2014 interim report.
[16] Prepared based on Table 2 in ESRA and reflects April 4, 2016 load forecast.

Table 3-2: Comparison of P90 Peak Forecasts[17]

	June 30, 2015, MW	Winter Readiness (Dec 1, 2015), MW	Diff., MW	Base Case (Apr 4, 2016), MW	Diff., MW	Diff., MW
	A	B	C=B-A	D	E=D-B	F=D-A
Winter 2016/17	1,846	1,798	- 48	1,801	3	- 45
Winter 2017/18	1,868	1,822	- 46	1,831	9	- 37
Winter 2018/19	1,868	1,813	- 55	1,819	6	- 49
Winter 2019/20	1,881	1,814	- 67	1,827	13	- 54

The Liberty Report has questioned the credibility of such a material reduction in forecast demand over this period, and notes that if this reduction in load does not actually occur there would be an increased risk of supply related interruptions on the IIS.[18]

Hydro prepares its medium term peak demand forecasts based on demand requirements provided by Newfoundland Power, Hydro's large industrial customers and Hydro's own demand forecasts for its rural service territory.[19] Hydro indicates that the reduced peak forecasts reflect updated information which indicates lower forecast demand requirements for Newfoundland Power (-21 MW), Island industrial customers (-29 MW) and system transmission losses (-12 MW), offset by a slight increase in the rural demand forecast (+6 MW).[20] Hydro provided the following explanation for the differences between the June 2015 peak forecast and the April 2016 peak forecast:

- **Newfoundland Power Load Forecast:** The June 2015 peak forecast was based on forecast information provided by Newfoundland Power in March 2015. The April 2016 forecast is based on an updated load forecast provided by Newfoundland Power in February 2016, and reflects lower system load growth projected by Newfoundland Power.
- **Industrial Load Forecast:** The change in Industrial customer peak demand requirements primarily reflects lower firm demand requirements for Vale. Vale's assessment of its production schedules reduced demand requirements by 30 MW.
- **System Transmission Losses:** Generally, the change in forecast transmission losses reflects overall lower customer demand levels; more specifically this reflects lower customer demand levels on the Avalon Peninsula. The reduction in system transmission losses also reflects impacts due to changes in the methods used by Hydro to estimate transmission losses between the June 2015

[17] Prepared based on Table 2 in ESRA and reflects April 4, 2016 load forecast.
[18] Liberty report, page 11.
[19] ESRA page 11.
[20] PUB-NLH-598 [ESRA].

forecast and the April 2016 forecast (i.e., Hydro notes that the April 2016 forecast used software that provided higher precision analysis).[21]

Hydro's 2013 Amended General Rate Application ("2013 Amended GRA") noted that "there will also be, in all likelihood, forecast error in both NP's and IIC's 2016 and 2017 load which may be significant."[22] The following is noted in this regard:

- Actual demand requirements are expected to vary to some degree from forecast due to factors such as extreme changes in weather conditions (very cold or very mild winters), as well as changes in economic and other local factors that may impact customer loads. The degree of forecast inaccuracy will also tend to increase with the duration of the forecast period (i.e., longer term planning forecasts which can look 10 to 20 years out are less likely to be realized compared to short term business planning forecasts which look only one to two years out).

- Industrial customers' forecast load requirements are typically based on each company's investment decisions as well as current market conditions, and industrial loads are also not typically directly weather sensitive.[23] Unexpected increases in industrial load over Power on Order are not common.[24]

- On the other hand, the demand from customers whose peak demand is largely impacted by extreme weather conditions may impact overall system reliability with sudden increases in demand. For example, Liberty notes that future peak loads "highly correlate to weather" and "IIS loads peak in the winter, which makes the wind-chill factor the defining variable.[25] The comparatively high penetration of electric heating among IIS electricity customers heightens the impact of this variable." Newfoundland Power's distribution system represents about 81% of the total IIS system demand[26] and it is very important that Newfoundland Power and Hydro work closely and frequently when developing load forecasts.

Considering above facts it is recommended that:

- Hydro revisit the near term load forecast using P90 as recommended by Liberty, and assess any risks related to sudden increases in the peak demand.

- Under the current circumstances more frequent load forecast exchanges between Newfoundland Power and Hydro would be beneficial to the IIS. It is recommended that Hydro and Newfoundland

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[21] ESRA, PUB-NLH-598.
[22] See response to CA-NLH-304.
[23] For example, Liberty in its December 17, 2014 Final Report notes that Hydro forecasts industrial peak demands by assuming continuation of medium-term demand requirements, unless it has a known closure date for an individual customer.
[24] For example, the historical load provided in response to IC-NLH-028 (Rev1, 2013 Amended GRA) shows that the non-coincident peak for NARL over 17 years period remained at average 30 MW level, CBPP non-coincident peak reduced over time reflecting reduced mill operations. There are increases in Power on Order from industrial customers during the ramp-up of operation activities [for example Vale and Praxair], however, the increases are expected and Hydro is notified in advance of such required increases based on contracts between parties.
[25] Liberty April 24, 2014 Interim Report, page 15.
[26] Estimated based on Hydro's response to PUB-NLH-598.

Power review the reasonableness of the Newfoundland Power load forecast for winter 2016/17 as well as forecast for near future years.

- Hydro work with industrial customers who are ramping up operation activities to determine any future increases are expected for these customers.

4.0 REASONABLENESS OF SYSTEM PLANNING AND OPERATING CRITERIA

It is in the interest of all IIS customers that appropriate criteria be used for system planning for the forecast and evolving pre-Muskrat Falls environment as well as the post-Muskrat Falls environment.

In the ESRA, Hydro relies on the following generation planning criteria[27] for system planning in order to avoid, or reduce, the risk of outages and unserved energy:

- **Loss of Load Hours (LOLH):** LOLH is a statistical assessment of the risk that the system will not be capable of serving the system's firm load for all hours of the year. Hydro's capacity planning criteria includes an LOLH expectation target of not more than 2.8 hours per year. This means that the IIS would be unable to serve all firm load for no more than 2.8 hours in a given year. Hydro indicates that based on this planning criteria, there is sufficient generating capacity on the IIS to satisfy a Loss of Load Hours (LOLH) expectation target of not more than 2.8 hours per year. Hydro notes that through correlation with Expected Unserved Energy (EUE) it determined that 300 MWh of EUE is approximately equivalent to an LOLH of 2.8.[28]

- **Reserve Margin:** Hydro notes that it has committed to maintaining a reserve of greater than 240 MW which would provide the ability to withstand the most onerous single contingency event (loss of Holyrood Unit 1 or 2) while maintaining a spinning reserve of 70 MW. Hydro notes that it does not use an N-1 criterion in the determination of generation adequacy for IIS, but uses LOLH and a reserve margin based on the current 240 MW target.[29]

- **Energy:** The IIS should have sufficient generating capacity to supply all of its firm energy requirements with firm system capability. Hydro notes that firm capability for hydroelectric resources is based on the most adverse three-year sequence of reservoir inflows occurring within the historical record; and the firm capability for the thermal resources (Holyrood) is based on energy capability adjusted for maintenance and forced outages.

The Liberty Report raises questions about Hydro's reliability standards and planning decisions, and indicates that the standards applied by Hydro provide "for lower reliability than what Liberty has observed in other regions of North America."[30] Liberty also notes that use of relatively low capacity reserves, which resulted from the higher LOLH, was one of the many factors that contributed to the supply shortage.[31]

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[27] ESRA pages 5-6.

[28] ESRA page 7. Expected Unserved Energy (EUE) is the summation of the expected number of MWh of load that will not be served in a given year as a result of demand exceeding available capacity. Loss of Load Hours (LOLH) measures the number of hours of shortfall, but does not provide number of shortfalls to quantify about how many days the outage is spread over.

[29] See response to IC-NLH-033 [ESRA]. The reserve margin threshold of 240 MW considers the most onerous single contingency to be the loss of 170 MW [IC-NLH-030, ESRA]. This is not specifically noted as N-1 criterion, but has similar characteristics. Hydro defines an N-1 condition as an operating condition where a major transmission asset (e.g. a 230kV or a 138kV transmission line, shunt capacitor banks, synchronous condensers or a transformer) has been lost, either due to maintenance or a fault [Liberty August 19, 2016 report, page 15].

[30] Liberty April 24, 2014 Interim Report, page ES-2.

[31] Liberty December 17, 2014 Final Report, page 11.

Liberty highlights the following inconsistencies and concerns regarding the use of the LOLH and EUE measures:

- While the LOLH target has rarely been an issue, the EUE target has not been met in four of the last five years.[32] This shows some inconsistency between these two reliability measures, i.e., while one measure indicates there are no reliability issues, the second measure indicates there are material issues as the target has not been met four out of five years.

- The LOLH maximum of 2.8 is the equivalent of one failure to meet demand in five years compared to once every ten years which is used by most other utilities in North America.[33] Liberty notes that Loss of Load Expectation (LOLE) of 0.1 is the "widely adopted, although not universally applied, North American standard"[34] and this could be translated into LOLH of 1.4 and 150 MWh EUE. However, this would be subject to Hydro's then-current modeling assumptions.[35] This implies that it may be appropriate to plan for fewer outage hours and unserved load compared to Hydro's current generation planning assumptions.

- Liberty notes that a bipole failure resulting from a single credible event (such as a tower failure) represents a single contingency and should be considered an N-1 event, not an N-2 event.[36] Liberty further comments that any high probability/high consequence event (such as a bipole failure) should be considered unacceptable for system planning.[37]

Based on the above, it is recommended that Hydro be directed to assess its reliability standards given that the isolated nature of the IIS grid pre-interconnection which require more stringent criteria compared to utilities with available access to external power sources at the time of emergency. These reliability standards need to be appropriate after interconnection and during post-Muskrat Falls conditions.

[32] Liberty August 19, 2016 Report, page 7.
[33] Liberty August 19, 2016 Report, page 6.
[34] IC-PUB-001.
[35] IC-PUB-002.
[36] Under N-1 criterion no loss of load with failure of most onerous single contingency; under N-2 criterion, system is designed for no loss of load for any two simultaneous failures.
[37] NP-PUB-016.

5.0 RELIABILITY OF THE EXISTING SYSTEM

The review to date raises questions regarding whether the system has sufficient reliable capacity; and regarding the most cost effective way to enhance the system and reduce vulnerability to outages that would adversely impact all IIS customers. Hydro and Liberty have indicated the following contrasting views on the adequacy of reliability capacity in the pre-Muskrat Falls environment.

- In the ESRA,[38] Hydro reviewed four feasible alternatives to mitigate a risk of outages and unserved load,[39] and concluded that a combination of advancement of TL267 in-service,[40] and retention of the Holyrood Diesels concurrent with the securing of an additional curtailable Avalon Peninsula load "provides reasonable mitigation of the risk for unserved energy through interconnection."[41]
- The Liberty Report raises concerns regarding the adequacy of the planning criteria used in Hydro's analysis, suggests that supply risks are greater than indicated by Hydro's assessment and recommends that a more detailed pre-Muskrat Falls supply assessment be undertaken. Liberty also notes that "adequate consideration of the risks, is likely to conclude that new supply is required in the near future,"[42] that the actions recommended in its report are urgent, and recommends that Hydro should, within three months from the time that the Board is able to issue such an Order, prepare and submit for Board review a plan to address the recommended actions.[43]

The record to date indicates that the following existing options are available at this time to avoid, or mitigate, the risk of system disruptions for both pre and post-Muskrat Falls conditions:

- **Maintain reliability of the existing thermal and standby capacity on the IIS:** Although there are concerns regarding reliability of the existing thermal and standby capacity in the IIS, there are no immediate alternatives available to replace them and this existing capacity continues to play an essential role in supporting near term IIS reliability. In the ESRA, Hydro does not provide comment on the reliability of the two Hardwoods and Stephenville CTs, however, in the 2017 Capital Budget application[44] Hydro notes that plants "are more than thirty years old, exceeding the generally accepted life expectancy of twenty-five to thirty years for gas turbine plants" and "the lack of availability of factory technical support and spare parts for these facilities" further

[38] Hydro reviewed its system and filed the ESRA report with the Board on May 27, 2016 noting that four feasible alternatives were reviewed to mitigate violation of LOLH criteria for a plant DAFOR of 14% when analyzed under a P90 load forecast.
[39] ESRA, page 25 through 30. Alternatives reviewed included the following: 1. Advancement of TL267 in-service; 2. Addition of standby generation on Avalon Peninsula; 3. Retention of the Holyrood Diesels concurrent with the securing of an additional curtailable Avalon Peninsula load; and 4. Additional investment in Holyrood plant assets. The assessment was done to mitigate violation of LOLH criteria with the Holyrood DAFOR of 14% and a P90 load forecast.
[40] TL267 is the third transmission line between Bay d'Espoir and Western Avalon Terminal Station. It is currently scheduled to be in service in Spring of 2018 before advancement. The line would help to reduce transmission line loses [Table 2, ESRA] as well as reduce Holyrood fuel costs [in some instances Hydro runs Holyrood to support Avalon transmission restraints – see pages 38 and 39 of June 5, 2015 pre-filed Testimony of P. Bowman and H. Najmidinov].
[41] ESRA, page 29.
[42] Liberty August 19, 2016 Report, page 12.
[43] IC-PUB-034 [Liberty Report].
[44] http://www.pub.nf.ca/applications/NLH2017Capital/files/applications/From%20NLH%20-%202017%20Capital%20Budget%20Application%20-%20Volume%20I%20-%202016-07-28.PDF, page 8.

complicates the issues in the plants. Regarding Holyrood Hydro notes that "is aged and near end-of-life", and that "systems and components may fail before problems can be identified and corrected".[45] Liberty concludes that the Holyrood oil-fired units and the Hardwoods and Stephenville CTs are primarily responsible for the system's vulnerability,[46] the Hardwoods and Stephenville CTs are unreliable, and extended outages are unavoidable if suitable backup supply is not in place to address both pre and post-Muskrat Falls conditions.

- **Explore more capacity assistance and load curtailment options:** Both Hydro and Liberty agree that capacity assistance and load interruption options are potential immediate term mitigation options that can benefit both the utility and IIS customers.[47] Undertaking capacity assistance and load curtailment requires material investment decisions to be made by participating customers – as such participating customers may require greater clarity regarding the acceptability of this as a solution for addressing reliability concerns pre and post-Muskrat Falls.

- **The need for new capacity:** The ESRA outlines that investment in a new standby option may be one alternative to addressing reliability concerns. However, the ESRA also concludes that the option with combination of advancement of TL267 in-service, retention of the Holyrood Diesels concurrent with the securing of an additional curtailable load would be more cost effective and would reasonably mitigate the risk of severe outages in the pre-Muskrat Falls environment. In contrast, the Liberty Report concludes that new supply "will be needed before Muskrat Falls is in service, to mitigate near-term supply issues, and after Muskrat Falls is in service, to mitigate the impact of extended outages of the Labrador-Island Link (LIL)."[48] The Liberty Report also notes that while Hydro's system design seeks to minimize the potential for outages, outages cannot be completely avoided, and adequate backup capacity should be available to prevent extensive and extended loss of load on the LIL.[49] Both Hydro and Liberty recognize that construction of new generation may not be available for at least two years[50] - and this would not be available to mitigate risk of outages for the next two winters, 2016/17 and 2017/18 winters.

In summary, the record to date indicates that maintaining existing thermal assets and capacity assistance/ load curtailment arrangements with large industrial customers are the key near term options available to mitigate the risk of system disruptions for both pre and post-Muskrat Falls conditions, and that more studies are required to identify the need for new generation supply. The following sections review in more detail the available options.

[45] ESRA page 28.
[46] Liberty August 19, 2016 Report, page 12.
[47] For example, in response to IC-NLH-064 [ESRA] Hydro notes that securing of incremental curtailable load on the Avalon Peninsula is the only option to reasonably mitigate expected unserved energy in excess of planning criteria for Winter 2016/17. In response to IC-PUB-007 [Liberty August 19 2016 Report] Liberty notes that this arrangements are often win-win for the customer and the utility, and enhance the reliability.
[48] Liberty August 19, 2016 Report, page ES-2.
[49] Liberty August 19, 2016 Report, page ES-3.
[50] Liberty's response to IC-PUB-008 notes that a cycle of 2-3 years would be realistic for construction of new combustion turbine. Hydro in ESRA notes that the construction schedule for new combustion turbine would not mitigate risks for 2016/17 winter.

5.1 MAINTAINING THE EXISTING THERMAL CAPACITY

The reliability of the existing thermal generation capacity needs to be reviewed and assessed. The ESRA indicates that expected unserved energy and LOLH expectation on the existing IIS are primarily influenced by the unavailability of Holyrood thermal units.[51] In contrast, Liberty notes that the Hardwoods and Stephenville CTs, as well as the Holyrood oil-fired units, are primarily responsible for the system's vulnerability.[52] Liberty also stresses that the need to replace Hardwoods and Stephenville should be included in the recommended review of Hydro's supply needs, and notes that any further spending on these units would raise questions regarding the prudence of such spending.[53]

5.1.1 Holyrood

Holyrood is a large, oil-fired generation plant with three generating units and a total Gross Continuous Unit Rating of 490 MW.[54] It is located on the Avalon Peninsula, a major IIS load centre, and plays a significant role in system reliability providing both peaking and base load energy. The record to date suggests that there is no economically feasible alternative to this large energy supply source, and that Hydro should continue to maintain Holyrood in a cost effective way to reduce adverse cost impacts to customers.

Liberty notes that Holyrood is required to remain in service until at least 2022, and that its service life will overlap with Muskrat Falls for several years; and indicates that it would not be prudent to immediately eliminate such a large source of power when the replacement source of power is only just commencing operations.[55] Liberty notes that the final retirement date of Holyrood would vary as a function of the successful demonstration of its replacement's reliability, i.e., Muskrat Falls and Labrador Island Link being proven to be highly dependable within their early years of operation would allow for an expedited retirement of Holyrood.

Hydro notes that it has maintenance and capital programs to maintain and refurbish/replace systems and components of Holyrood, but also recognizes that "as the plant is aged and near end-of-life, systems and components may fail before problems can be identified and corrected."[56] Available information shows that the cost of plant-in-service for Holyrood was $192.1 million in the 2010 actual cost-of-service study, and was forecast to increase to $256.9 million in the 2015 test-year cost-of-service study.[57] This was a cost increase of about $65 million (or 34%) over a five year period, or an average increase of $13 million annually (or approximately $0.026 million/MW on 490 MW nameplate capacity) to maintain the thermal generation plant. This level of ongoing expense appears to be reflected the current status of generation capacity [as highlighted by Hydro the plant is aged and near end-of-life], and is comparable to the neighbouring province's spending to maintain its thermal generation capacity. Specifically, Nova Scotia

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[51] ESRA page 10.
[52] Liberty August 19, 2016 Report, page 12.
[53] IC-PUB-006 [Liberty Report].
[54] The first two units at 170 MW and Unit 3 at 150 MW.
[55] IC-PUB-005 [Liberty Report].
[56] ESRA page 28.
[57] Schedule 2.2A of 2015 cost-of-service provided in 2013 Amended GRA application and Schedule 2.2A of 2010 cost-of-service provided in IC-NLH-002 [original 2013 GRA application].

Power's 10 Year System Outlook – 2016 Report (please see Appendix C for extract pages from the document)[58] shows that its average annual investment to maintain thermal units (including coal, oil fired, CT and biomass) is about $50 million/year based on average for 2017-2021 years for approximately 2,000 MW of installed capacity (or about $0.025 million per year per MW).

During the 2016 Capital Budget review process, the Holyrood boiler tubes were noted to be at highest risk of failure and absent replacement the units would need to be de-rated.[59] The capital budget included provision for replacement of the lower reheater boiler tubes on Units 1 and 2, and additional reliability improvements at the Holyrood Thermal Generating Station at a cost of $11.8 million.[60] Hydro also subsequently retained Amec Foster Wheeler (Amec) to complete a more detailed assessment on Holyrood units.[61] Liberty indicates that the Amec Report provides encouraging results, the planned de-rate of the units is now far less than originally planned, and the high level of concern regarding future Unit 1 and 2 failures has been largely eliminated.[62]

As described above, there is no economically feasible alternative to this energy supply source and Holyrood plays an important role in IIS reliability. Therefore, Hydro should continue to maintain Holyrood as a reliable energy supply source, but in a cost effective way to reduce adverse cost impacts to customers.

5.1.2 Stephenville and Hardwoods CTs

The Hardwoods Gas Turbine Plant (Hardwoods) was constructed in 1976 and is located in the west end of the city of St. John's; and the Stephenville Gas Turbine Plant (Stephenville) was commissioned in 1975 and is located in the town of Stephenville. Both plants operate in either generation mode to provide peak and emergency power or as synchronous condensers to provide voltage support to the IIS.[63] Stephenville and Hardwoods combustion turbine have a Gross Continuous Unit Rating of 50 MW each.

The evidence indicates some disagreement between Hydro and Liberty regarding the reliability of these combustion turbines:

- Hydro's Risk Assessment report does not raise any concerns regarding the availability of the combustion turbines, and Hydro notes the ongoing importance of these plants in its capital budget applications. Specifically, Hydro has noted that the retirement of the Hardwoods and Stephenville gas turbines is not expected until 2025 and 2028[64], respectively, and that "These facilities

[58] Figure 12, Nova Scotia Power's 10 Year System Outlook – 2016 Report. Extracts from the Outlook are provided in Appendix C. Page 13 of the outlook shows winter net capacity with thermal capacity totalling to 1,895 MW. This does not include 30 MW fuel oil unit expected to be back in service in 2017, and a biomass plant at 60 MW. The document is available at: http://oasis.nspower.ca/site/media/oasis/20160630%20NSPI%20to%20UARB%2010%20Year%20System%20Outlook%20Report.pdf [accessed on October 5, 2016].

[59] PUB-NLH-009 2016 Capital Budget. http://www.pub.nf.ca/applications/NLH2016Capital/NLHCBSUPP2016/Boilertubes/files/rfis/PUB-NLH-009.PDF.

[60] http://www.pub.nf.ca/applications/NLH2016Capital/NLHCBSUPP2016/Boilertubes/files/application/Application-ApprovaloftheReplacementoftheboilerTubesonUnits1and2atHolyroodThermalGeneratingStation-2016-03-29.PDF.

[61] The copy of the report provided to the Board on August 12, 2016 – Holyrood TGS Boiler Tube Thinning Assessment.

[62] Liberty August 19, 2016 report, page 8.

[63] http://www.pub.nf.ca/applications/NLH2016Capital/NLHCBSUPP2016/EngineRefurbishments/files/application/Application-GasGeneratorEngineRefurbishmentsatHardwoodsandStephenvilleGasTurbinePlants-2016-05-19.pdf.

[64] Hydro's 2017 Capital Budget application, page 8.

accumulate few operating hours generating electricity but are crucial sources of power and energy during emergencies and system peaks and provide voltage support, especially when operating as synchronous condensers."[65] Hydro also notes that "synchronous condensing is an important function of the Hardwoods and Stephenville gas turbine plants and "all three of Hydro's gas turbine plants provided significant generation to the IIS in 2016 to support reliable customer service."[66]

- On the other hand, Liberty concludes that Hydro should include the need to replace Hardwoods and Stephenville in the recommended review of supply needs, and notes that any further spending on these units may raise questions regarding the prudence of such spending.[67]

The following indicates a strong basis for concern regarding whether this capacity will actually be available when required.[68]

- **Reliance on these units has been an issue in each of the last three winters:** The Liberty April 24, 2014 Interim Report shows that the Hardwoods CT was not available for the duration of the early January customer disruptions, while half of the Stephenville CT capacity was not available into early January 2014.[69] Liberty's August 19, 2016 report also notes that in early 2016, the Hardwoods and Stephenville CTs both failed within six weeks of one another. Hydro responses to RFIs during the review of Hydro's application for Gas Generator Engine Refurbishment – Hardwoods and Stephenville[70] also shows unavailability of the CTs due to failures in the equipment.

- **Lack of recent assessment to confirm reliability and prudence of future spending:** Hydro spent about $14.1 million over 2007-2015 on Stephenville and $12.6 million on Hardwoods.[71] During 2016 Capital Budget review process Hydro applied for Gas Generator Engine Refurbishments for both plants at a cost of $3.1 million.[72] Hydro's 2017 Capital Budget application includes forecast spending for gas turbine life extension for both plants [Stephenville at $1.353 million over 2017-18 years and Hardwoods at $0.956 million over 2017-18 years].[73] Hydro has not assessed the CTs in recent years to confirm their reliability and prudence of future spending on this costly energy supply option.[74] During Hydro's 2015 Capital Budget review process, Hydro included a 2007 Stantec

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[65] Hydro's 2015 Capital Budget application. See page 7 of the 2015 Capital Projects Overview and page 5 of the Capital Plan section of the Application. Source: http://www.pub.nf.ca/applications/nlh2015capital/INDEX.HTM.
[66] See Hydro's 2016 Capital Budget Supplementary application for Gas Generator Engine Refurbishments – Hardwoods and Stephenville.
[67] IC-PUB-006 [Liberty Report].
[68] Liberty August 19, 2016 report page 9.
[69] Pages 20 and 21.
[70] The responses to IC-NLH-001 and IC-NLH-002. http://www.pub.nf.ca/applications/NLH2016Capital/NLHCBSUPP2016/EngineRefurbishments/files/rfis/IC-NLH-001.PDF.
[71] Hydro's 2016 Capital Budget response to NP-NLH-014 at http://www.pub.nf.ca/applications/NLH2016Capital/NLHCBSUPP2016/EngineRefurbishments/files/rfis/NP-NLH-014.PDF.
[72] http://www.pub.nf.ca/applications/NLH2016Capital/NLHCBSUPP2016/EngineRefurbishments/files/application/Application-GasGeneratorEngineRefurbishmentsatHardwoodsandStephenvilleGasTurbinePlants-2016-05-19.pdf.
[73] Hydro's 2017 Capital Budget application http://www.pub.nf.ca/applications/NLH2017Capital/files/applications/Pages%20B-5%20and%20B-6%20(Rev%201)%20-%202016-09-29.PDF.
[74] In addition to the capital requirements, the energy output from the turbines are very high compared to the other sources. For example, the response to IC-NLH-009 during Hydro's 2015 Capital Budget review shows the energy output from the plants at $0.27/kW.h for Hardwoods and $0.49/kW.h for Stephenville.

Condition Assessment Study Report in response to a request to provide copies of all reports which consider or discuss the options for decommissioning or replacement of the Hardwoods Gas Turbine plant and Stephenville Gas Turbine plant.[75]

In summary, it is clear that there are reliability issues with the units, and that they have been often unavailable when needed. It is recommended that Hydro undertake a detailed review of the Stephenville and Hardwoods units as part of any review of supply needs and make recommendations to the Board regarding their future status. Although these plants are costly to Hydro and its customers, there is no immediate alternative available that can replace these capacity options. Consequently, the plants should be maintained until a new alternative option is available.

5.2 ROLE OF THE CAPACITY ASSISTANCE, INTERRUPTIBLE/CURTAILABLE LOAD

The Liberty Report has highlighted the important role that interruptible/curtailable load arrangements can play and has recommended that Hydro continue discussions with appropriate industrial customers to secure capacity assistance needed to avoid risks with outages in the system as experienced in 2014.[76] This section provides an overview of the role that interruptible and curtailable load and capacity assistance agreements have played on the IIS to date, and outlines the benefits that capacity assistance/ load interruption arrangements can provide to all customers in both pre and post Muskrat Falls conditions.[77] While not all customers can provide capacity assistance,[78] it is noted that all customers can benefit from these arrangements.

Context – Existing Role of Interruptible/Curtailable Load on IIS

On isolated systems, such as the IIS, interruptible and/or curtailable load can play a significant role in enhancing system reliability at the time of generation or transmission/distribution constraints, and help to avoid the use of higher cost generation sources that impose financial costs and inconvenience on customers and the utility. Having interruptible load also benefits system operational security by lowering the likelihood and consequences of forced outages. The following is specifically noted regarding the existing context for interruptible load on the IIS:

- **Interruptible Load is consistent with existing regulatory requirements:** Section 3 (b) (i) and (iii) of *Electrical Power Control Act* (*EPCA*), 1994[79] requires that the system be managed and viewed on a consolidated basis, with an aim to minimizing overall consolidated costs, ensuring efficiency in overall consolidated system operation, and in maximizing reliability and availability of

[75] http://www.pub.nf.ca/applications/NLH2016Capital/NLHCBSUPP2016/EngineRefurbishments/files/rfis/IC-NLH-005.PDF. 2007 Stantec Condition Assessment Study Report (http://www.pub.nf.ca/applications/NLH2016Capital/NLHCBSUPP2016/EngineRefurbishments/files/rfis/NP-NLH-013.PDF).

[76] Liberty August 19, 2016 Report, follow-up RFI responses and April 24, 2014 Liberty Interim Report page 37.

[77] In this section the interruptible load definition also captures the capacity assistance agreements with major industrial customers.

[78] For some industrial customers load interruptions would result in adverse impacts due to their obligations on commercial agreements and may result on lost/damage to the equipment/production lines. It is also important to note that capacity assistance and load interruption arrangements require a large investment decision by the industrial customer which would have long-term impacts for the customer.

[79] *Electrical Power Control Act*, 1994, http://www.assembly.nl.ca/legislation/sr/statutes/e05-1.htm.

power.[80] The use of the load interruptions/curtailment for reliability driven interruptions is consistent with the provisions of *EPCA, 1994*. In particular, dropping loads where customers have elected to receive a lower priority of service (and are appropriately compensated), increases the efficiency of the system dispatch, increases reliability for firm power customers, and reduces the overall costs of delivering reliable power to the province as other more expensive options for providing the equivalent capacity can be avoided.

- **Historic Load Curtailment Arrangements (1993-2003):** The power system in Newfoundland has benefited in the past from load curtailment. From 1993 through 2003, Hydro had Interruptible B agreement in place with a major industrial customer that provided Hydro with the ability to call upon the industrial customer at any time during the four winter months to reduce their power consumption by up to 46 MW.[81]

- **New Capacity Assistance Arrangements (2014):** In the aftermath of outages on the IIS in January 2014, Hydro started discussions with large industrial customers to enter into new capacity assistance arrangements. Currently, Hydro has the following load curtailment and capacity assistance agreements:

  - **Capacity Assistance Agreement with CBPP** - This agreement allows Hydro to call on CBPP for up to 60 MW of capacity assistance during winter peak demand periods by both reducing its firm demand supplied by Hydro (about 9 MW), and by providing 51 MW of capacity to Hydro's system from the CBPP hydraulic generating facilities.

  - **Supplemental Capacity Assistance Agreement with CBPP** - This supplemental agreement with CBPP provides for an additional net capacity assistance of approximately 22 MW[82] through a further interruption by CBPP of its operating load that is normally provided by its hydro generating facility.

  - **Capacity Assistance Agreement with Vale** - This agreement provides up to 15.8 MW of capacity assistance to Hydro’s system from Vale’s standby diesel generating facilities.

  - **Newfoundland Power curtailable load** - This is generally in the range of 8 to 10 MW[83] and applicable for generally shorter-term interruptions than those available to Hydro under the existing capacity assistance agreements. Hydro also filed an application with the Board to secure a curtailable program with Newfoundland Power. Newfoundland Power maintains

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[80] 3. It is declared to be the policy of the province that (b) all sources and facilities for the production, transmission and distribution of power in the province should be managed and operated in a manner (i) that would result in the most efficient production, transmission and distribution of power, … (iii) that would result in power being delivered to consumers in the province at the lowest possible cost consistent with reliable service.

[81] Interruptible B contract with ACCC-Stephenville for maximum of 46 MW [NP-136 NLH, 2003 GRA]. In response to IC-194 NLH [Hydro’s 2003 GRA] Hydro noted that “deficits in capacity are not forecast until 2011” and therefore Hydro decided not to renew the contract.

[82] The Supplemental Capacity Assistance Agreement provides for up to 30 MW of capacity assistance. However, this level of assistance would shut down the co-generation unit (about 8 MW) for a net benefit of 22 MW to the Island Interconnected System.

[83] Hydro’s September 19, 2014 application before PUB for approval of revisions to Utility rate to Newfoundland Power.

that this program only be used at the time of system constraints in exchange for "curtailable credit" offered to Newfoundland Power.[84]

5.2.1 Pre-Muskrat Falls Conditions

Hydro's 2015-2016 Winter Capacity Assistance Report notes that Hydro made 13 requests for capacity assistance from CBPP and Vale during the winter period and "these capacity requests helped to maintain reserves on both the Island and Avalon Peninsula systems and Hydro was able to reliably maintain supply to customers."[85]

Capacity assistance arrangements can play a vital role and provide benefits to all customers on the IIS in both pre and post-Muskrat Falls conditions:

1. **Flexibility of the available capacity:** At times of system constraint participating large industrial customers can be interrupted pursuant to established load shedding guidelines. For example, the capacity agreement with CBPP indicates that within 20 minutes of Hydro providing notice to the customer, capacity assistance can be available to avoid any adverse impact to the system. In contrast, smaller customers are typically shed much later in the system response sequence. For these smaller customers more coordination is needed, and compared to industrial customers there are more risks related to non-compliance with the load shedding request.

2. **Timing of the available capacity:** Capacity assistance is required immediately to help mitigate system reliability concerns in the pre-Muskrat Falls period. This need has only been enhanced with the delay of Muskrat Falls full in-service. Capacity assistance/curtailable loads are already available to mitigate system capacity constraints and do not require regulatory approvals and/or construction to implement. Hydro notes that "it remains Hydro's opinion that the securing of incremental curtailable load on the Avalon Peninsula is the only option to reasonably mitigate expected unserved energy in excess of planning criteria for Winter 2016/17."[86]

3. **Cost effective:** In its October 28, 2014 application for approval of the capacity agreement with CBPP, Hydro noted that the capacity credit of $28 per kW per winter "is materially lower than the average marginal capacity cost on the Island Interconnected System for the next three years."[87] Capacity assistance agreements also benefit the system, Hydro and all of its customers by reducing or avoiding the following types of future costs:

    a. **Marginal Fuel Costs** - Available capacity assistance helps Hydro avoid fuel costs that would otherwise be incurred by running Holyrood or other combustion turbines.[88]

    b. **Facility Construction/Maintenance Costs** - Capacity assistance reduces the need to construct and maintain utility generation units required to serve an equivalent load.

[84] The Board Order P.U. 47 (2014).
[85] Hydro's 2015-2016 Winter Capacity Assistance Report to the Board, page 4. Filed with PUB on April 14, 2016.
[86] IC-NLH-064. RFI response provided by Hydro in review of Hydro's Risk Assessment report.
[87] Page 8 of Evidence – Capacity Assistance Procurement Process and Considerations provided in the application.
[88] Page 7 of Evidence – Capacity Assistance Procurement Process and Considerations provided in the October 28, 2014 application before the Board for approval of capacity agreement with CBPP.

Pursuant to capacity assistance contracts currently in place, the capacity relied upon is used and maintained by the industrial customer at its own cost. When required it can be dispatched to serve system needs.

4. **Benefits for all on IIS:** Liberty[89] notes that capacity assistance/load curtailment agreements are often win-win for the customer and the utility, and enhance the reliability of supply on the system (which benefits all customers).
   a. All customers in the system benefit from enhanced supply reliability on the system and comparative lower costs and fuel savings as noted above. Since all energy savings are manifested as savings in Holyrood fuel oil or combustion turbine, all customers benefit.
   b. The system and utility also benefit from enhanced supply reliability for the system and comparative lower costs and fuel savings as noted above.
   c. Industrial customer participant benefits from bill savings and incentive payments for the risk assumed for each shut down, as well as the impacts associated with reductions or breaks in operations as a result of providing capacity assistance.

The load curtailment program applicable to Newfoundland Power similarly provides benefits the IIS when used to help mitigation of system emergencies and to Newfoundland Power (incentives from Hydro as reduced billing demand).

In the post-Muskrat Falls environment, capacity assistance/interruptible loads are expected to continue providing benefits to the IIS, with similar benefits to utilities and customers as described above in Section 5.2.1. With the addition of both Muskrat Falls and LIL sourced power and Maritime Link connection in operation, the value of maintaining power supply capacity within the IIS, will continue. Capacity assistance/interruptible loads will also continue to be valuable to the IIS in this environment.

5.2.2 Impact of Conservation Demand Management

The Newfoundland and Labrador Conservation and Demand Management Potential Study: 2015 completed for Hydro and Newfoundland Power in 2015 indicates that "demand reduction potential is dominated by the reductions associated with demand response curtailment measure, with much of this potential already in place through existing utility curtailment programs."[90]

- Hydro has noted that it "will actively consult with its industrial customers and Newfoundland Power to determine the potential of securing any incremental curtailment load that remains within their systems."

[89] Response to IC-PUB-007 [Liberty August 19 2016 Report].
[90] Available at http://www.pub.nl.ca/applications/IslandInterconnectedSystem/files%5Creports%5CNLConservationandDemandManagementCDMPotentialStudy-IndustrialSectorFinalReport-June2015-09-16.pdf [accessed on October 11, 2016]. Also referenced in ESRA pages 27 and 28.

- Liberty has noted that the impact from conservation demand management may be small, however, "when a borderline situation exists, every saved MW can be of real value; hence, such efforts should be encouraged."[91]

Undertaking the efficiency programs can provide benefits to the system, but may require material investment decisions to be made by participating industrial customers. As such, participating customers may require greater clarity regarding the options offered by program.

As Liberty noted the impact from conservation demand management may be small, but it still can provide benefits to the system, especially in a pre-Muskrat Falls environment. Therefore, continued efforts in this regard should be encouraged.

5.2.3 Conclusions

Capacity assistance/interruptible load arrangements provide benefits to utility, participants and IIS customers in both the pre and post-Muskrat Falls environments. Hydro should continue to be encouraged to investigate for additional sources while seeking ways to avoid and/or mitigate system reliability concerns. Participation in capacity assistance/interruptible load arrangements require customers to make material investment decisions. Hydro should consider longer term contracts and incentive payments for the risk assumed for each interruption, as well as the impacts associated with reductions or breaks in operations as a result of providing capacity assistance.

5.3 THE NEED FOR NEW CAPACITY

The record to date has identified concerns regarding the both the need for new capacity on the IIS and the volume of new supply required.

- After reviewing a new standby option as an alternative in its ESRA, Hydro concluded that other options would be more cost effective and would also provide reasonable mitigation regarding the risk of unserved energy through interconnection.

- In contrast, Liberty notes that new supply "will be needed before Muskrat Falls is in service, to mitigate near-term supply issues, and after Muskrat Falls is in service, to mitigate the impact of extended outages of the Labrador-Island Link (LIL)."[92] Liberty also notes that new pre-Muskrat Falls supply for IIS would not necessarily take the form of new investment in combustion turbines, and that power that would likely solve the pre-Muskrat Falls supply issue can be imported on both the LIL (110 MW potential recall power from Labrador) and the ML (300 MW potential from Nova Scotia) when these lines are in service.[93]

- Liberty concludes that Hydro should prepare a new supply review in order to evaluate the degree to which new capacity is required to ensure that customer outages due to loss of the LIL bipole

[91] April 24, 2014 Interim Report, page 37.
[92] Liberty August 19, 2016 Report, page ES-2.
[93] Liberty August 19, 2016 Report, page 12.

are limited to those caused by under-frequency load shedding (UFLS) and those circuits are promptly (within hours) restored.[94] Liberty acknowledges that "there are many variables that make a superficial estimate by Liberty unreasonable, including pre-Muskrat Falls needs, revision of the load forecast, potential replacement of Hardwoods and Stephenville, and the potential to move to an LOLE of 0.1."[95]

New capacity would add significant benefits to system reliability, but also raises the following concerns.

- The costs associated with new standby generation would need to be recovered through customer rates. This would include both the cost of construction as well as maintenance costs which would be incurred regardless of whether new generation units are dispatched or not.
- Any new capacity would not be immediately available. Both Hydro and Liberty recognize that construction of new generation may take up to two years[96] which would not mitigate the risk of outages for the next two winters.

Given these considerations, the new capacity option needs to be carefully assessed against the other available options.

The alternatives to new supply can vary depending on available and required capacity and it is recommended that Hydro undertaken and assessment to determine its supply needs before determining whether new generation capacity is required for pre and post-Muskrat Falls conditions, as recommended by Liberty. The following areas that may impact the requirement for new capacity and that should inform any review are noted below:

- Updates to the load forecast and planning criteria;
- Available capacity assistance and load curtailment options pre and post Muskrat Falls, as well as any reduction in load that can be achieved through Conservation Demand Management;
- The condition of Stephenville and Hardwoods CTs and whether Hydro's review confirms that both CTs can be relied upon when needed with minimal annual maintenance costs;
- Capacity available through Maritime Link is expected to be in service in Q3 of 2017[97] which is earlier than potential in service for any new supply option; and
- Recall capacity available through Labrador-Island Link is expected to be in service in Q2 of 2018[98] which is earlier than potential in service for any new supply option.

[94] Under-frequency load shedding (UFLS) is triggered when supply becomes insufficient to meet demand and is used to avoid system collapse.
[95] Liberty's response to IC-PUB-032.
[96] Liberty's response to IC-PUB-008 notes that a cycle of 2-3 years would be realistic for construction of new combustion turbine. Hydro in ESRA notes that the construction schedule for new combustion turbine would not mitigate risks for 2016/17 winter.
[97] ESRA IC-NLH-025.
[98] ESRA IC-NLH-025.

6.0 RELIABILITY OF THE LIL AND ML

In the pre-MF environment, Hydro has identified both the LIL and ML as possible sources of power to help meet load requirements on the IIS.[99] The LIL has the potential to provide 110 MW in the pre-MF period using firm recall power from Churchill Falls. In the post-MF period, the LIL is assumed to be committed to transmission of MF generation to the IIS and the ML.

Hydro has assumed that the ML can contribute up to 300 MW to the IIS, providing notable benefits to the IIS in both the pre-MF period, where non-IIS generation may be available to displace IIS sources, and in the post-MF period if required to mitigate extended LIL outages.

Liberty and other intervenors have raised questions and concerns regarding the reliability, availability and practicality of these operating assumptions for the LIL and the ML. These concerns need to be addressed in the near term to help ensure that suitable mitigation measures are available and in place for the IIS.

6.1 LABRADOR-ISLAND LINK (LIL)

Use of the LIL to help mitigate IIS reliability concerns is limited to the period of time immediately preceding MF in-service when firm recall power is available from CF to meet IIS load requirements. After MF is in-service, the LIL will be used solely to meet domestic IIS and export ML needs.

Liberty notes that the technical feasibility of using recall capacity before Muskrat Falls in service has not yet been established[100], and would represent a small fraction of LIL capacity[101]. Liberty is not familiar with every restraint to feasibility of recall power that may exist, but notes that low short circuit level at Muskrat Falls without Muskrat Falls generation in service may present some challenges in ac voltage control, and it may be necessary to develop special controls to make the switching of ac harmonic filters acceptable.[102]

Liberty has also commented that having the generation for IIS located at a significant distance from the load center is unique in Canada.[103] It is noted, however, that Manitoba generation stations are similarly located at significant distances from the load centre [HVDC length for Manitoba Hydro is about 950 km compared to 1,100 km for NLH LIL]. Although reliability is enhanced when generation is located near the load centre, given the timing and potential length of IIS interruptions, potential use of the ML as a backup source should not be ruled out.

If additional power is technically available over the LIL during this pre-MF period, Hydro should be confirming in the near term that the concerns identified by Liberty and others can be effectively mitigated.

[99] ESRA, May 2016, page 20.
[100] Liberty August 19 2016 Report, page 12; Liberty's responses to IC-PUB-014.
[101] Liberty's responses to IC-PUB-012.
[102] CA-PUB-036, CA-PUB-50.
[103] Liberty response to CA-PUB-049.

6.2 MARITIME LINK (ML)

Hydro has identified use of the ML to help mitigate both pre and post-MF reliability concerns on the IIS.[104] However, Liberty has noted commercial concerns associated with implementing this option that should be addressed in the short term. While the availability of the Nova Scotia capacity has not yet been validated, Liberty confirms its only concerns regarding ML supply are commercial, i.e., Hydro needs to enter into agreements that provide the required capacity.[105]

In a post-Muskrat Falls environment, the Liberty Report notes that the Maritime Link benefits the IIS even with the agreements currently in place. Most importantly, the Maritime Link is interruptible to the extent supply on the LIL is lost. The Liberty Report also notes the Maritime Link may provide significant benefits that enhance IIS reliability, and also highlights the need to carefully consider the assumed reliance on import capacity through the Maritime Link from Nova Scotia.[106]

- In the event of an LIL interruption, Nova Scotia would have to replace the power it loses from Muskrat Falls and provide additional capacity for the IIS. The Liberty Report notes that the "extent to which reliance can be placed on the Maritime Link as a source of dependable generation and the competitiveness of such supply are not certain at this time."[107]

- Both Nova Scotia and Newfoundland utilities experience system peaks at the same time (i.e., during cold winter months), and neighboring provinces could also have severe weather conditions at the same time. Consequently, both utilities could need additional capacity at the same time, which would require a large back up capacity. The Liberty Report notes that the cost for such a large amount of backup would need to be balanced against the risk of an LIL trip, as well as the competing cost of new supply options.

- At the moment of a LIL interruption, power would not be immediately available from the ML. Liberty notes Hydro's response to PUB-NLH-512 "discussions with Nova Scotia have resulted in the concept of instantaneous power reversal on the Maritime Link as unacceptable."[108] The forecast system peak for Nova Scotia Power between 2016-2020 would range between 2,130 and 2,180 MW [with about 93% being firm load and the remaining interruptible] compared to the installed capacity of about 2,500 MW.[109] Nova Scotia Power was planning to retire the Lingan 2 unit on Cape Breton Island at 153 MW in 2018 after Muskrat Falls was in service.[110] However, with Muskrat Falls delays it is unknown if/when this or other units will actually be retired. Liberty notes the potential

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[104] ESRA, May 2016, page 20.
[105] CA-PUB-051 [Liberty August 19, 2016 Report].
[106] For example, on pages 76 and 85 of its report Liberty highlights that import of 300 MW of power to the IIS is likely to be unacceptable to the Nova Scotia power system and the credibility or practicality of this source of capacity has been demonstrated.
[107] Liberty August 19, 2016 Report, page ES-4.
[108] See IC-PUB-017, PUB-NLH-512, Liberty August 19 2016 Report, page 76.
[109] NSPI to UARB: 10 Year System Outlook Report, Figure 2, page 8. http://oasis.nspower.ca/site/media/oasis/20160630%20NSPI%20to%20UARB%2010%20Year%20System%20Outlook%20Report.pdf [accessed on October 11, 2016].
[110] NSPI to UARB: 10 Year System Outlook Report, page 25. The link provided in the previous footnote. Also see Figure 10 in Appendix C to this report.

availability of Nova Scotia power for the IIS would depend on commercial agreements between parties.

Liberty provided a redacted copy of the August 2016 Liberty audit report of NSP for NS UARB.[111] The report confirms increased transmission constraints between NSP and NBP in recent years. The lack of firm transmission through NB has precluded delivery of firm energy to NSP. From 2009 to 2015, NB firm transfer capability reduced from 300 MW to zero in winter months (20 MW in summer months) and non-firm capability reduced from 550 MW to 200 MW (reduced further when NB system load exceeds 2,300 MW). There is some discussion of potential changes with ML and imports from Muskrat Falls, as well as potential costs of options to improve NB/NS transmission. Liberty recommended NSP develop strategy (with plan to NS UARB before end of 2016) to improve access to power ties from the west to gain full competitive benefits of new ML energy access from the east.

There is benefit to resolving these issues in the near term, and it is recommended that the studies identified by the Liberty Report be completed to ensure that the mitigation options identified by Hydro effectively address identified system reliability concerns.

The studies identified include completing the determination of the capacity availability from Nova Scotia, the anticipated terms and pricing, confirming the availability of capacity to the IIS through the LIL pre-Muskrat Falls, and completing system integration studies highlighted in the Liberty Report.

[111] NP-PUB-009 [Liberty August 19, 2016 Report].

APPENDIX A:

JOHN OSLER'S QUALIFICATIONS

InterGroup CONSULTANTS

JOHN OSLER
PRESIDENT

AREAS OF EXPERIENCE:

- Socio-economic Assessment
- Economic Impact Assessment
- Public Engagement

EDUCATION:

- M.B.A. (Finance and Marketing), University of Sheffield, England, 1991
- B.A. (Honours) (Economics), University of Manitoba, 1990

PROFESSION AFFILIATIONS:

- Member, International Association for Public Participation (IAP2)
- Member, International Association for Impact Assessment (IAIA)

RELEVANT PROFESSIONAL EXPERIENCE:

InterGroup Consultants Ltd. **Winnipeg, Manitoba**
1991 – Present **Consultant/Manager/Principal/President**

For the Manitoba Industrial Power Users Group – Project Principal from early 1990s to 2010. John assisted in Manitoba Hydro electricity rate hearings before the Manitoba Public Utilities Board for Industrial customers on matters including revenue requirement, electricity policy, cost of service and rate design. Oversaw development of the economic impact assessment for MIPUG members, participated in government and key stakeholder consultations on behalf of members and in charge of member communications. Participated in development of the Curtailable Rate Program, an industrial rate designed for energy efficiency and system reliability. Participated in policy initiatives including bill affordability program considerations for customers.

For the Government of the Northwest Territories - Assisted with intervention at the 1993/94 NWT Power Corporation Phase II rate design and cost of service hearing before the Public Utilities Board. This work included detailed technical analysis of the application, cost of service study assumption and analysis, rate design proposals and impact to the customers.

For the Yukon Energy Corporation - Assisted with: financial and strategic planning; review and planning for 1991 General Rate hearings before the Yukon Utilities Board; preparation for 1992 Cost of Service/Rate Design Hearing; preparation of submission document for 1992 Capital Plans hearing; preparation for 1992 Capital Plans Hearing; preparation for 1992/93 General Rate Application. Review and preparation of a discussion paper on Demand Side Management in Canada.

For Manitoba Transportation and Government Services - Analysis and development of a briefing document assessing the impact of government policy and legislative changes on three Manitoba Government departments, including consideration of future trend implications.

For BC Hydro - Research, data compilation and cost-benefit analysis of the effects of river regulation on a community downstream of a hydroelectric project. This project included working with the local residents and identifying impact of the large hydroelectric project, providing recommendations and analysis.

For Westcoast Power - Prepared a preliminary cost-benefit analysis for a proposed cogeneration facility in Manitoba. This project included review of the benefits associated with the cogeneration project, including securing the long term viability of the mill and the town of Pine Falls, lowering the costs associated with the generation, increased efficiency, and forecast demand. The project also reviewed and quantified benefits of the project to the province, including creating jobs and tax revenues to the economy.

For the Alberta Department of Energy - Research and analysis related to curtailable and price responsive load transition issues for large industrial energy loads.

For The Forks North Portage Partnership - Review of utility expenses and advice on rate and cost recovery optimization.

For the Manitoba Entertainment Complex - Assistance with the development coordination to establish a new arena complex in Winnipeg, including financial modelling, economic impact assessment, marketing management, and public consultation.

For Regional Municipality of Ottawa Carleton - Economic cost-benefit assessment of landfill life extension and optimization options, including economic and financial modelling.

For the Aggregate Producers in Ontario - Socio-economic impact and resource policy evaluation relating to proposed aggregate developments in southern Ontario (Puslinch, Milton and Niagara Escarpment Planning Area); review of and implications for the Town of Caledon official plan (OPA 161) with respect to the development of aggregate resources in the Greater Toronto Area.

APPENDIX B:

HAMID NAJMIDINOV'S QUALIFICATIONS

HAMID NAJMIDINOV
RESEARCH CONSULTANT

AREAS OF EXPERIENCE:

- Utility Regulation
- Resource Planning Analysis

EDUCATION:

- Bachelor of Science (Economics), Fergana State University, 2000

RELEVANT PROFESSIONAL EXPERIENCE:

InterGroup Consultants Ltd. — **Winnipeg, Manitoba**
2009 – Present — **Research Analyst / Research Consultant**

For Qulliq Energy Corporation (2009-Present): Actively involved in the preparation of Phase I and Phase II of 2010/11 and 2014/15 General Rate Applications, including preparation of sales and revenue forecast, revenue requirement, amortization and ratebase schedules, territory-wide and community based Cost of Service analyses, rate design and rate schedules; provide support in the preparation of Major Project Permit Applications and Fuel Stabilization Rider Applications.

For Yukon Energy Corporation (2009-Present): Provided support in preparation of 2009 GRA Phase II application (bill impacts analysis; cost of service review; revenue-cost ratio analysis) and actively involved in preparation of 2012/13 GRA Phase I application; support in budget planning and in preparation of regulatory reports; support in preparation of Yukon Energy's 20-Year Resource Plan update (load forecast update; alternative generation benefit analysis); performed power benefit analysis for Mayo B and Mayo Lake projects; provided support in preparation and review process of LNG project Part III application; support in DCF/ERA application and analysis. Provided support in 2016 Resource Options Evaluation.

For Northwest Territories Power Corporation: Provide support in developing monthly load and revenue forecasts for budget planning; proposed territory-wide levelized rate structure analysis; cost of service comparison and rates analysis between utilities in different jurisdictions; potential mini-hydro projects benefit cost analysis.

For Industrial Customers of Newfoundland and Labrador Hydro (2013-Present): Review and provide support in analysis for Newfoundland and Labrador Hydro's 2013 GRA and Amended GRA, including components of revenue requirement, cost of service, rate design, RSP, interim rate applications and other proposals; prepare requests for information, pre-filed evidence, provide support in oral hearing processes; customer rate impact analysis and customer briefs.

For Manitoba Hydro – Keeyask Generation Project: Provided support for the socio-economic impact assessment; KCN communities Population Projection Model support and updates; project employment estimates analysis; Northern Aboriginal employment estimates, including modeling based on employment demand and supply analysis and updates; project construction employment income analysis.

For Viability Analysis of a South-East Alaska and Yukon Economic Development Corridor (2014): Perform financial and quantitative data analysis and modelling assessments as required to assess the viability of the Skagway-Whitehorse economic development corridor options under relevant load and resource project scenarios, analysis for viability of the transmission corridor.

For Nelson Hydro (2014; 2016 current): Review revenue requirement allocations to Urban and Rural systems and develop system allocation factors using capital and O&M costs; develop a Cost of Service model for each system; rate analysis; review profit margins and return on equity for comparable municipality owned utilities across Canada; prepared report.

For City of Penticton (2015): Utility rate review for electric, water and sewer utilities, including review and development revenue requirement for each utility focusing on reduced impact to customers from capital projects and phase-in options for other cost components; load forecasts for each utility; developed a Cost of Service model and rate design with phase-in rate options, involved in preparation presentation to the Council and report.

Feed-in-tariffs (2016): Review Feed-in tariff rate setting methods in Canada as well as in some States in the USA for renewable energy power purchase agreements.

Economic Profile of Alaska Highway – Yukon Government (2015): Perform financial and quantitative data analysis for economic profile of the Alaska Highway, including impact to Yukon economy and economic sectors.

Financial Evaluation for ranking of Geothermal Renewable Energy Options – Yukon Energy through KGS Group (2016): Perform financial evaluation analysis for geothermal renewable energy options.

North Salt Spring Waterworks District (2016): Parcel Tax Reform. The assignment includes review of the existing parcel tax structure, analyse water consumption behaviours of the customer classes, review parcel tax structure in the other water districts and peer municipalities, development of new parcel tax structure including rate impact and phase in options.

APPENDIX C:

EXTRACTS FROM NOVA SCOTIA POWER 10-YEAR SYSTEM OUTLOOK, 2016

Nova Scotia Utility and Review Board

IN THE MATTER OF *The Public Utilities Act,* R.S.N.S. 1989, c.380, as amended

Nova Scotia Power 10 Year System Outlook

2016 Report

June 30, 2016

1 **Figure 4: 2016 Firm Generating Resources**

Plant/System	Fuel Type	Winter Net Capacity (MW)
Avon	Hydro	6.8
Black River	Hydro	22.5
Lequille System	Hydro	26.2
Bear River System	Hydro	38.2
Roseway[5]	Hydro	0.0
Tusket	Hydro	2.4
Mersey System	Hydro	42.5
St. Margaret's Bay	Hydro	10.8
Sheet Harbour	Hydro	10.8
Dickie Brook	Hydro	2.2
Wreck Cove	Hydro	210.0
Annapolis Tidal[6]	Hydro	3.5
Fall River	Hydro	0.5
Total Hydro		**376.3**
Tufts Cove	Heavy Fuel Oil/Natural Gas	321
Trenton	Coal/Pet Coke/Heavy Fuel Oil	307
Point Tupper	Coal/Pet Coke/Heavy Fuel Oil	152
Lingan	Coal/Pet Coke/Heavy Fuel Oil	617
Point Aconi	Coal/Pet Coke & Limestone Sorbent (CFB)	171
Total Steam		**1568**
Tufts Cove Units 4,5 & 6	Natural Gas	146.7
Total Combined Cycle		**146.7**
Burnside[7]	Light Fuel Oil	90
Tusket	Light Fuel Oil	30
Victoria Junction	Light Fuel Oil	60
Total Combustion Turbine		**180**
Pre-2001 Renewables	Independent Power Producers (IPPs)	25.8
Post-2001Renewables (firm)[8]	IPPs	44.7
NS Power wind (firm)[8]	Wind	5.3

[5] The timing of the return to service of the Roseway potion of the Roseway/Harmony system is pending decisions with regards to level of refurbishment.
[6] The capacity of the Annapolis Tidal unit is based on average performance level at peak time. Nameplate capacity (achieved at low tide) is 19.5 MW.
[7] Burnside Unit #4 (winter capacity of 30 MW) is presently unavailable but is planned to be returned to service in 2017.
[8] The firm capacity value assumed for wind depends on the type of interconnection service. Energy Resource Interconnection Service (ERIS) projects have a firm capacity assumption of zero, consistent with the Generation Interconnection Procedures (GIP). These projects may not possess one or more of the physical characteristics required in order to provide capacity service. Network Resource Interconnection Service (NRIS) projects are considered firm for capacity planning because they possess the necessary physical characteristics and transmission capacity to ensure full operation in all hours of the year.

dates planned such that maintenance expenditures and depreciation can be aligned to that date. This is achieved using a comprehensive asset management approach which specifies maintenance strategy, provides a detailed understanding of equipment health, rigorously calculates risk, and mitigates risk with consideration for unit utilization.

At present, NS Power is in a hold position as it pertains to our steam fleet. One exception is Lingan Unit 2, which will retire with the commissioning of the Maritime Link and the flow of the Nova Scotia Block of energy and consequent firm capacity. **Figure 10** below provides the Steam Fleet Retirement Forecast Outlook from the 2014 IRP.

Figure 10: Steam Fleet Retirement Forecast Outlook

Unit	Commissioning Year	2014 IRP Retirement[1]	Year Fully Depreciated[2]	Federal Coal Regs Retirement[3]
Lingan 1	1979	2039	2023	2029
Lingan 2	1980	2018	2021	2029
Lingan 3	1983	2039+	2039+	2029
Lingan 4	1984	2039+	2039+	2029
Point Aconi	1994	2039+	2039+	2044
Point Tupper	1972/1987	2039+	2039+	2021
Trenton 5	1969	2035	2039+	2019
Trenton 6	1991	2039+	2039+	2041
Tufts Cove 1	1965	2025	2027	N/A
Tufts Cove 2	1972	2032	2033	N/A
Tufts Cove 3	1976	2036	2039+	N/A

[1] The retirement assumptions used for the 2014 IRP. Units with retirements beyond 2039 (the planning horizon) were not given specific retirement years for modeling purposes.
[2] The year in which the unit is fully depreciated at the current rates of depreciation.
[3] The retirement dates of the coal units under the Federal GHG Regulations (if the Equivalency Agreement were not in effect).

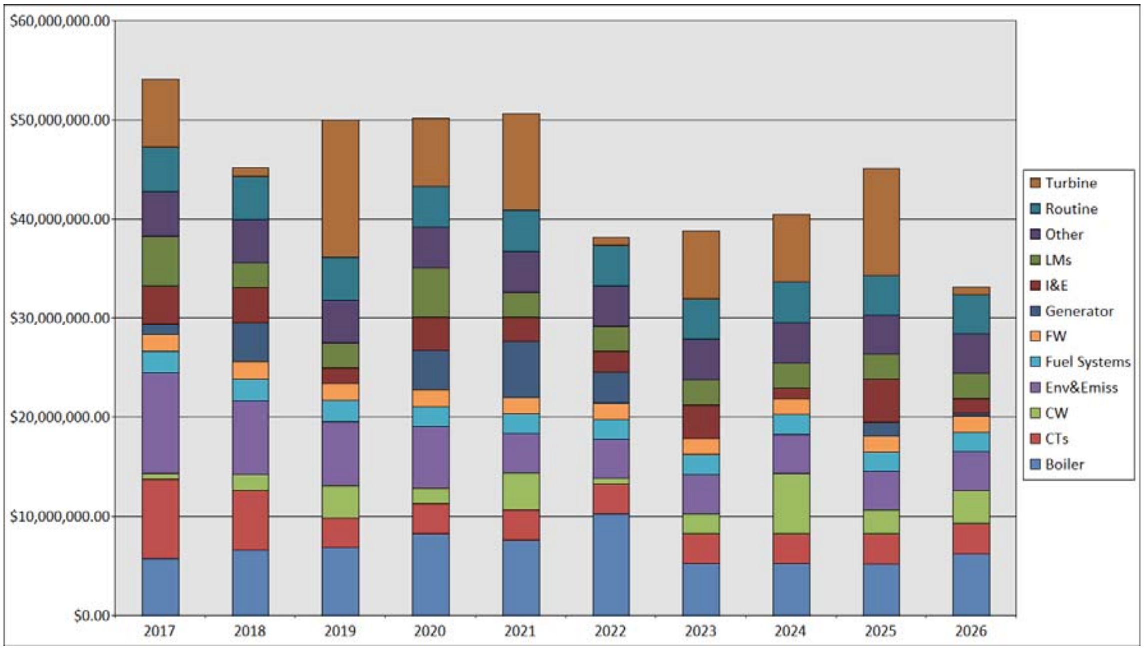
The retirement of Tuft's Cove 1 in 2025 as per the 2014 IRP Assumptions is not included in the projected system outlook this year. The forecasted peak customer demand from the 2016 Load Forecast indicates a capacity short fall will exist if this unit is retired in 2025. This retirement decision is far enough in the future that the projected life of Tuft's Cove Unit 1 can be extended if necessary, or other options can be evaluated in that time to ensure an effective strategy is selected to provide capacity. This emphasizes the advantage of maintaining planning flexibility for NS Power to allow sufficient time to react to evolving forecasts and policy changes.

NS Power continues to monitor developments in other jurisdictions related to coal generation and air emissions policy. Implications for replacement of firm capacity as well as depreciation schedules would need to be considered in any policy shift in Nova Scotia or Canada, provoking advancements in unit retirements.

4.3.3 Projections of Unit Sustaining Investment

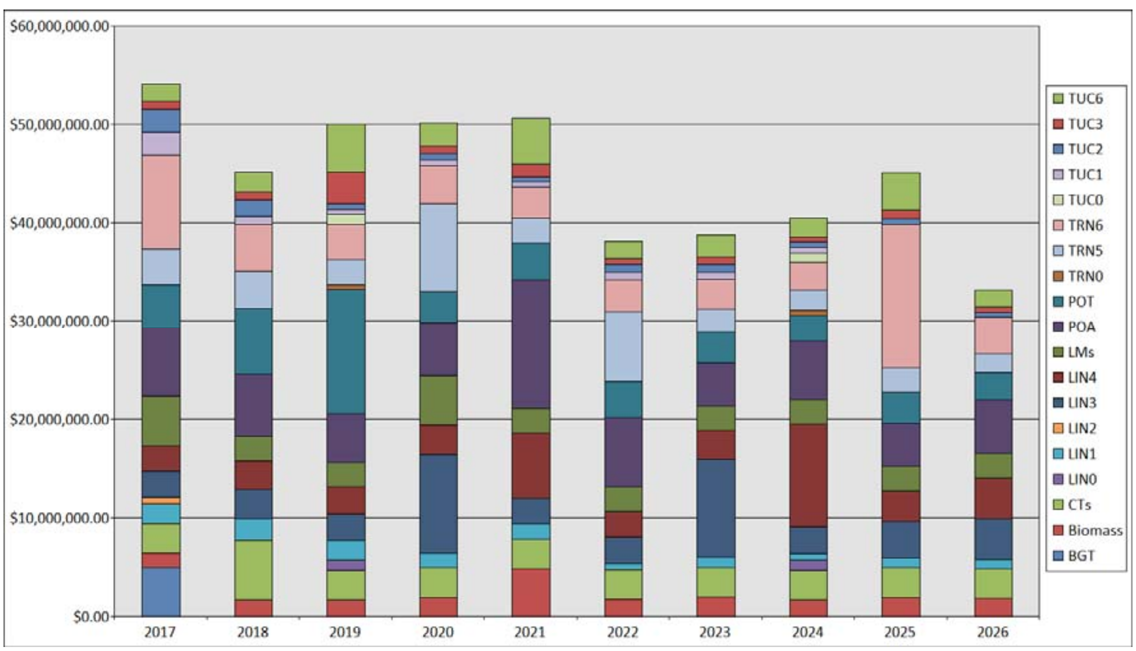
Figure 11 and **Figure 12** below provide the sustaining investment projected based on the anticipated utilization forecasted in Section 4.3.1. Estimates of unit sustaining investment are projected using the application of Utilization Factor (UF), discussed in Section 4.3.1, and other considerations. These are evaluated at the asset class level; some asset class projections are prorated by the UF and others have additional overriding factors. For example, the use of many instrument and electrical systems is a function of calendar years, as they operate whether a unit is running or not. Investments for coal and ash systems are a direct function of capacity factor, as they typically have handling volume based failure mechanisms. In contrast, the UF is directly applicable to the investment associated with turbines and boilers. Major assets are regularly re-assessed in terms of their condition and intended service as NS Power's operational data, utilization strategy, asset health information, and forecasts are updated.

Figure 11: Forecasted Annual Investment by Asset Class



Note: Figure does not include escalation as it is used for asset planning
Forecasted investments are subject to change arising from asset health and actual utilization.

Figure 12: Forecasted Annual Investment by Unit



Note: Figure does not include escalation as it is used for asset planning