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February 6, 2015

The Board of Commissioners of Public Utilities
Prince Charles Building
120 Torbay Road, P.O. Box 21040
St. John's, Newfoundland & Labrador
A1A 5B2

Attention: Ms. Cheryl Blundon
Director Corporate Services & Board Secretary

Dear Ms. Blundon:

Re: The Board's Investigation and Hearing into Supply Issues and Power Outages on the Island Interconnected System – Newfoundland and Labrador Hydro's Reply to the Phase I Report by Liberty Consulting

This is further to the Board's correspondence of January 9, 2015 and January 22, 2015 wherein Hydro is required to submit its position on the conclusions and recommendations of the Liberty Group Report of December 17, 2014. Please find enclosed the original plus 12 copies of Hydro's Reply Submission in this regard.

We trust the foregoing is satisfactory. If you have any questions or comments, please contact the undersigned.

Yours truly,

NEWFOUNDLAND AND LABRADOR HYDRO

Geoffrey P. Young
Senior Legal Counsel

GPY/jc

cc: Gerard Hayes – Newfoundland Power
Paul Coxworthy – Stewart McKelvey Stirling Scales
Sheryl Nisenbaum – Praxair Canada Inc.
Thomas Johnson – Consumer Advocate
Thomas O' Reilly – Cox & Palmer
Danny Dumaresque

ecc: Roberta Frampton Benefiel – Grand Riverkeeper Labrador

Investigation and Hearing into Supply Issues and Power Outages on the Island Interconnected System

Newfoundland and Labrador Hydro's Response to the Phase I Report by Liberty Consulting (the Hydro Reply)

Newfoundland and Labrador Hydro

February 5, 2015

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Appendix A Summary of Hydro's Responses to Liberty's Phase I Recommendations

1 BACKGROUND

1.1 System Disruptions – January, 2014

On January 2, 2014 the total system load on the Island Interconnected System (the "IIS"), and the available generation supply to meet this load, converged to a point where it was necessary to issue a request for conservation to the general public. As system load increased further going into the late afternoon of January 2, it became necessary for Newfoundland and Labrador Hydro ("Hydro" or the "Company") to request that Newfoundland Power initiate rotating outages, and these continued into January 3.

On January 4, an unrelated event involving the failure and destruction by fire of a 230 kV transformer at the Sunnyside terminal station resulted in a wide disruption of power supply to the Avalon Peninsula and other areas. This event, and the failure of individual 230 kV breakers at Sunnyside and other locations set in motion a series of transmission system and generation events that extended the need for rotating outages through to January 8.

1.2 The Regulator's Investigation into Supply Issues and Power Outages

On January 10, 2014 the Board of Commissioners of Public Utilities (the "Board") announced its intention to hold an inquiry and hearing into recent supply issues and power outages. On February 19, 2014 the Board issued Order No. P.U. 3 (2014). This Order outlined a process that contemplated both an Interim Report and a Final Report by the Board. Correspondence from the Board at the time indicated the Board's intention to issue its Interim Report in April, 2014 and to issue its Final Report by the end of March, 2015. The issues to be addressed in the Board's Interim Report were outlined in the Board's Order as follows:

a) Explanation of the Island Interconnected System events that occurred in December, 2013 and January, 2014;
b) Evaluation of possible Island Interconnected System changes to enhance preparedness for 2014-16; and,
c) Examination of each utility's response to the power outages and customer issues.

The Board's Order further identified the issues to be addressed in its Final Report as follows:

a) Comprehensive analysis of the Island Interconnected System events of December, 2013 and January, 2014;
b) Evaluation of Island Interconnected System adequacy and reliability up to and after the interconnection with the Muskrat Falls generating facility; and,
c) Examination of customer communication and service enhancement.

The Liberty Consulting Group ("Liberty") were retained by the Board in January, 2014 to examine the causes of the outages experienced by customers on the Island Interconnected System between January 2 and January 8, 2014. Liberty presented its Interim Report to the Board on April 24, 2014 in advance of the Board's Interim Report which was released on May 25, 2014. Liberty's Final Phase I Report (the "Report") was presented to the Board on December 17, 2014.

On October 31, 2014 the Board advised Hydro and interveners that its review of supply issues and power outages would proceed in two phases: a) Phase I would focus on the adequate and reliable supply of power on the Island Interconnected System for the upcoming winter seasons until the interconnection with Muskrat Falls, and b) Phase II would focus on the implications of the interconnection with Muskrat Falls on reliability and adequacy of the Island Interconnected System. The specific issues to be considered within Phase I were identified as follows:

a) Causes of the December 2013 and 2014 supply issues and power outages;
b) The response by Newfoundland and Labrador Hydro and Newfoundland Power, including emergency preparedness and rotating outages;
c) Customer service strategies, including customer communications;
d) Response and action in relation to the findings of the Board in its Interim Report;
e) Asset management practices of both utilities;
f) Newfoundland and Labrador Hydro's load forecasting practices;
g) Adequacy of utility resources to operate and maintain the Island Interconnected System;

h) Governance and decision making at Newfoundland and Labrador Hydro;
i) Coordination between the utilities; and,
j) The role of conservation and demand side management in load management on the Island Interconnected System.

The anticipated schedule for the completion of Phase I of the Board's investigation was set out by the Board on January 9, 2015 as follows:

a) January 12, 2015 – RFIs on Liberty's Reports and to other parties.
b) January 28, 2015 – Responses to the RFIs fled on January 12.
c) February 5, 2015 – Submissions by Hydro and Newfoundland Power including their position on Liberty's Reports.

1.3 Hydro's Internal Investigation and Review

The impact on customers of the January, 2014 system events was significant and extended. With this in mind, and consistent with Hydro's focus on continuous improvement, Hydro initiated an internal investigation of these supply disruptions and outages on January 10 immediately following system restoration. The primary purpose of this review was to identify any actions, conditions or other factors that contributed to these disruptions and outages, and to identify immediate and longer-term actions required to prevent similar events from occurring in the future.

Another important purpose of this review was to identify what went well in Hydro's response to these events and in the efforts made to restore service as safely and as quickly as possible, to enable sharing and learning across Hydro and with other organizations.

1.3.1 Investigation Framework

Hydro's internal review was structured to be both expeditious and comprehensive in nature. The Company's primary goal was to quickly identify, and where possible, act on any conditions or factors that caused or contributed to the supply shortages and outages that occurred in January.

Consistent with prudent industry practice, a comprehensive framework was developed to guide this review and ensure that all appropriate areas of investigation were covered. Teams were formed to review the Company's performance in the following eight areas:

1. Load forecasting
2. Generation/reserve planning
3. Generation availability
4. Transmission availability
5. Asset management strategy and practices
6. Coordination and communication with customers
7. Emergency response and restoration
8. Technology and communications infrastructure

Guidance was provided to internal teams regarding the component areas of each of the above that should be included within the scope of their respective reviews. These component areas are noted below.

1. Load Forecasting
   a) Performance during the events
   b) Underlying assumptions and related risk of error
   c) Communication between Planning and Operations
   d) Overall integrity of the forecasting methodology

2. Generation/Reserve Planning
   a) Planning performance leading up to and during the events
   b) Reliability criteria and operating assumptions
   c) Risk profile as operating load forecasts increase over time
   d) Options for incremental generation

3. Generation Availability
   a) Gas Turbine availability
   b) Holyrood availability
   c) Hydro generation availability
   d) Wind generation availability

4. Transmission Availability
   a) Transmission performance
   b) Breakers/terminal stations
   c) Protection and control response

5. Asset Management Strategy and Practices
   a) Asset Management strategy and standards
   b) Maintenance execution
   c) Long Term Asset Plans
   d) Critical spares strategy
   e) Councils of Experts

6. Coordination and Communication With Customers
   a) Communication and outage coordination with Newfoundland Power
   b) Corner Brook Pulp and Paper
   c) Communication with the general public/end users
   d) Customer conservation

7. Emergency Response and Restoration
   a) Power restoration response

8. Technology and Communications Infrastructure
   a) Energy Management System
   b) Computer and telecommunications network/devices

1.3.2 External Resources

While Hydro relied considerably on internal resources to complete this review, the Company also made extensive use of independent external experts. These included Blair Seckington and Brian Scott of AMEC Americas Limited and Charles Henville of Henville Consulting Inc., who produced independent reviews of the Company's asset management strategy and practices (Seckington) and various aspects of transmission system performance at Hydro (Scott and Henville). All of these individuals have extensive utility industry experience in

Canada and other parts of the world, and were qualified to provide an objective and informed perspective on the areas they were asked to review.

Mr. Brian Tink, an external TapRoot Process Matter Expert, facilitated the work of the multi-disciplinary team[1] (that included OEM representatives as well) that was assembled to complete structured root cause analyses[2] of the four key transmission/terminal station equipment failures that occurred on January 4 and 5, 2014, noted below.

1. Sunnyside Terminal Station T1 transformer failure;
2. Sunnyside Terminal Station 230 kV bus lockout;
3. Western Avalon Terminal Station T5 transformer lockout; and
4. B1L17 circuit breaker failure in the Holyrood Switchyard.

Hydro also engaged Ventyx (an ABB company) to complete an independent review of its load forecasting and generation planning processes. Ventyx are recognized experts who provide consulting services to energy companies in the areas of integrated resource planning, resource evaluation and planning, and other related areas. The Ventyx final report was received by Hydro on March 20, 2014.

The independent reports completed for Hydro are noted below.[3]

1. **Ventyx, an ABB company** -- (Load Forecasting and Generation Planning)
2. **AMEC Americas Limited --** Brian Scott (Transmission Availability)
3. **Henville Consulting Inc**. – Charles Henville (Protection & Control Impacts)
4. **AMEC Americas Limited** – Blair Seckington (Asset Management Strategy and Practices)

[1] See PUB-NLH-075 for further details regarding the composition of this team.
[2] Hydro used the TapRooT® process, a systematic and structured process for identifying causal factors and associated root causes that are linked to events such equipment failures.
[3] These reports were included in Volume II of Hydro's Internal Review Report submitted to the Board on March 24, 2014.

1.3.3 Hydro's Response and Action Plan

The follow-up actions identified through Hydro's internal review, together with actions recommended by Liberty's Interim Report, were consolidated into a 2014 Integrated Action Plan (IAP) (copies of Hydro's monthly IAP updates are available on the Board's web site). A majority of the 82 actions in Hydro's IAP were focused on the highest priority areas identified by Hydro in its review:

a) Generation planning
b) Load forecasting
c) Generation reliability
d) Transmission reliability
e) Winter readiness
f) Customer communication and notification

Other outage-related action plans that both complemented and supplemented the IAP were developed and executed in 2014 as well. These are discussed in more detail in later sections of this Reply, and they include the following:

a) Supplemented Annual Work Plan to include Incremental preventive and correction maintenance activities;

b) 2014 Incremental Capital Program (including the new CT at Holyrood; transformer replacement at Sunnyside; transformer refurbishment at Western Avalon; and 230 kV breaker replacements); and,

c) Generation Master Plan for Winter Preparation.

Hydro's continuing follow-through on outage-related work will be integrated into Hydro's 2015 IAP, and will incorporate the following:

a) Items in the 2014 IAP which indicated 2015 completion dates;
b) Items in the 2014 IAP carried over into 2015; and,
c) Actions required in response to recommendations made by Liberty in their Report.

2 INTRODUCTION

In this Reply, Hydro sets out its specific response to each of the recommendations made by Liberty in their Report. These responses are summarized in Appendix A of this Reply, and they are discussed in more detail in the sections which follow, along with Liberty's supporting conclusions in each case.

Hydro is in substantial agreement with Liberty's additional recommendations in their Phase I Report, particularly those that are focused on equipment availability and reliability and the management and maintenance of aging generation and transmission assets. Sections 3, 5 and 6 of this Reply in particular address the areas of generation planning, load forecasting, generation availability, and transmission availability, and Hydro appreciates Liberty's comments on the significant progress that was made in 2014 in these areas. Hydro is confident that the actions it has taken to date, and those it will continue to take as outlined in this Reply, to increase available generation capacity on the IIS, and to improve the reliability of its generation and transmission assets, will continue to sustain reliable service up to the in-service of Muskrat Falls and beyond.

Significant progress has also been made in other important areas related to emergency preparedness, outage management, and customer coordination and communication. Hydro has acted on the many continuous improvement opportunities identified during both its own internal review of the January, 2014 events and Liberty's Interim Report, and it will continue to monitor the effectiveness and responsiveness of these processes on an ongoing basis.

3 GENERATION PLANNING AND POWER SUPPLY

3.1 Planning and Load Forecasting

3.1.1 Power Supply Planning

3.1.1.1 Actions Taken by Hydro

Hydro's processes for long-term generation planning were not identified as a contributing factor to the supply issues and outages which occurred in January, 2014. However, in the course of its own internal review and Liberty's Phase I review, the processes and methodologies used for identifying the need for capacity additions were extensively reviewed and discussed. These processes are key to ensuring that required additions to generation capacity are implemented in a timely manner relative to system requirements, and that adequate reserve margins are in place to offset system generation contingencies and/or extreme load conditions.

Various actions were taken by Hydro in 2014 to improve its generation planning processes. The most important of these involved completing an update to the Company's generation expansion analysis. This update incorporated increased sensitivity assumptions related to weather and generation unit forced outage rates, as recommended by Ventyx (Hydro's system vendor) and then subsequently by Liberty. Hydro has since integrated a wider sensitivity analysis into its generation planning process on a go-forward basis as proposed and used in the generation expansion analysis supporting the April, 2014 Capital Application "Supply and Install 100 MW Combustion Turbine". This analysis assumed load forecast based on P90 weather, and for generation availability a 2% increase in the De-Rated Adjusted Forced Outage Rate (DAFOR) for the units at the Holyrood Thermal Generating Station, combined with a 10% increase in the Utilization Forced Outage Rate (UFOP) for the combustion turbines at Hardwoods and Stephenville.

A related key action was IAP#6, where Hydro committed to revisit its generation planning reserve criterion, with consideration given to the availability of external markets after the in-service of Muskrat Falls in 2017. Given Hydro's priority focus on winter readiness for the 2014/15 winter season, this action was identified for completion in 2015, which is consistent with the recommendation made by Liberty in their Report.

Further information on Hydro's actions in this area is provided in the following sections.

3.1.1.2 Recommendations by Liberty Consulting

Table 3.1 below identifies Liberty's recommendations and associated conclusions in relation to power supply planning.

TABLE 3.1
LIBERTY'S CONCLUSIONS & RECOMMENDATIONS – POWER SUPPLY PLANNING

RELATED CONCLUSION(S)	RECOMMENDATION	
Hydro has made major improvements in its load forecasting capabilities as they apply to supply planning (2.1). Liberty continues to consider the P90 forecast as the preferred planning base (2.5).	2.4	Continue to include the P90 load forecast prominently in all evaluations of power supply adequacy.
	2.7	Validate a reasonable and practical criterion for reserve margins, although not necessarily in the form of a rigid number, and characterize the degree of risk associated with that criterion.
	2.8	Report quarterly on the rolling 12-month performance of its units, including actual forced outage rates and their relation to: (a) past historical rates, and (b) the assumptions used in the LOLH calculations.
	2.9	Report promptly to the Board any potential change in the outlook for the adequacy of supply, including increases in forecasted peaks or reductions in unit availabilities.

P90 Weather Forecast

Liberty indicates that a P90[4] forecast on weather is the preferred planning base for forecasting the annual winter peak for supply planning purposes. However, Liberty did not recommend that P90 be used as the sole weather criterion. Liberty recognizes that the key issue is the extent to which decision-makers consider the P90 effect in their deliberations, and Liberty have acknowledged that Hydro's current approach of evaluating reserve calculations on both a P50 and P90 basis gives sufficient visibility to the P90 case (see Liberty's response to GRK-PUB-013). Hydro agrees with Liberty's conclusions 2.1 and 2.5 and with their recommendation 2.4 in this context. Hydro adopted its current approach in 2014 as part of its updated generation expansion analysis, and intends to continue using this approach as recommended by Liberty.

Reserve Margin Criterion

The events of January 2-8, 2014 demonstrated that the Newfoundland IIS was at risk of not being able to supply customer load when there are multiple generating units unavailable during sustained cold weather. In the past, the IIS has experienced comparable levels of generation unavailability and cold weather conditions, but the winter of 2014 was the first time these occurrences aligned to result in a supply shortfall.

Hydro's response to the January 2014 events has been twofold: 1) actions have been taken to increase the IIS's ability to serve load through the accelerated addition of a planned combustion turbine[5], and the negotiation of approximately 96 MW of capacity assistance[6]

[4] P90 is an indicator of probability. P90 implies there is a 90% probability that the actual weather causing the annual winter peak will be lower than the forecast. Similarly, P50 would imply that the actual weather causing the annual winter peak has an equal probability of being either above or below the forecast.

[5] Originally Hydro planned for the addition of a 60 MW combustion turbine to be in-service in the Fall of 2015. The actual combustion turbine Hydro acquired is a 123.5 MW unit which is currently available under emergency generation scenarios while the final commissioning activities are being completed.

[6] Capacity assistance refers to agreements in place between Hydro and two of its industrial customers, Corner Brook Pulp and Paper Limited and Vale, to provide Hydro with a net relief of approximately 96 MW through load management and customer generation.

with industrial customers, effectively adding over 200 MW of new capacity for the winter of 2014/15; and 2) increased efforts to improve the winter availability of existing generation and transmission equipment.

Historically, Hydro has used a P50 weather forecast assumption for forecasting the winter peak and assessing generation adequacy. With a P50 forecast there is a 50 % probability that the actual peak load will be greater than the forecast due to the weather. Hydro has since also incorporated the use of a P90 weather forecast to assess generation adequacy and the level of generating reserve. With a P90 forecast the probability of the actual load exceeding the forecast due to weather is only 10 %.

Table 3.2 below summarizes Hydro's generation reserve outlook through to 2018/19 incorporating the most recent P90 load forecast for the IIS and the capacity additions made in 2014. This analysis includes:

a) The new Holyrood combustion turbine at a capacity of 123.5 MW and capacity assistance in the order of 80 MW available from Corner Brook Pulp and Paper and 10.8 MW available from Vale (increasing to 15.8 MW in 2015-16).
b) 20 MW of demand reduction is available through a controlled voltage reduction at time of peak at major Newfoundland Power delivery points. Newfoundland Power has been successfully using this technique for a number of years to manage the demand on their system.

Table 3.2 Forecast Reserve Margins 2015-2018 based on P90 Load Expectation						
Winter	**IIS Peak at P90**	**Capacity at Peak**[7]	**Voltage Reduction (+20)**	**Capacity Assistance**[8] **(+96)**	**MW Reserves at P90**	**% Reserve at P90**
2014-15	1770	1998	2018	2109	339	19.1%
2015-16	1813	1998	2018	2114	301	16.6%
2016-17	1844	1998	2018	2114	270	14.6%
2017-18	1865	1998	2018	2114	249	13.4%
2018-19	1879	1998	2018	2114	235	12.5%

With a P90 peak load forecast, Table 3.2 indicates expected reserves of 19.1% (339 MW) in 2014-15, declining to 13.4% (249 MW) in 2017-18. In the unlikely event that Muskrat Falls, the Labrador Island Link and the Maritime Link are all delayed by one winter season to 2018-19, Table 3.2 indicates an expected reserve of 12.5% (235 MW).

In addressing Liberty's recommendation 2.7 regarding the development of a reserve criterion, the central question for Hydro, electricity customers, and all other electricity system stakeholders is this – *what is the lowest reasonable level of reserve for the IIS between now and 2017/18 or 2018/19 knowing that the Island will be interconnected through both Labrador and Nova Scotia once Muskrat Falls interconnections are in-service?* The answer requires a consideration of the dynamics of the IIS, the contingencies that could occur, and the level of reserve that would be required to mitigate these contingencies.

[7] Based on peak capacity reported to the PUB in Hydro's "Daily Island Supply and Demand Report", reflecting current capacity of 1,875 MW + 123.5 MW (new CT) = 1,998 MW. Peak capacity does not consider any contribution from the wind generation on the IIS (approximately 50 MW).

[8] Incorporates ccapacity assistance at 90.8 MW during the 2014/15 winter period, increasing to 95.8 MW for the 2015/16 winter period and beyond.

Steady State Operation: Study and operational experience has shown that, in order to adequately manage normal daily generation and load variations, a minimum spinning reserve[9] of approximately 70 MW is desirable. While it is possible to operate with spinning reserves less than 70 MW, 70 MW should be considered the minimum spinning reserve for planning purposes. This would equate to a reserve of approximately 4%

N-1 Generation Contingency: The most onerous single generation contingency would be the loss of either Holyrood Unit 1 or Unit 2 at 170 MW. To withstand this loss, system reserves would need to be 70 MW (spinning reserve) + 170 MW (maximum generation loss), for a total of 240 MW, or approximately 13%.

Multiple Unit Generation Contingency: The Hydro owned generation fleet on the IIS is comprised of more that 20 individual units, only five of which have capacities greater than 120 MW, with the remaining units being 80 MW or less. Multiple unit contingencies of the smaller units are quite manageable with reserves at or above 240 MW. However, multiple contingencies involving the larger units such as the Holyrood units, Bay d'Espoir Unit 7, or the new Holyrood CT could present a challenge. The following examples illustrate some of the possible contingencies involving these larger units.

> *N-2 Contingency involving the loss of Holyrood Units 1and 2***:**
> Generation Loss = 340 MW
> Required reserve = 340 MW + 70 MW spinning reserve = 410 MW (~22%-23% reserve)
>
> *N-2 Contingency involving Holyrood Unit 1 or 2 and one of Units 1-6 at Bay d'Espoir:*
> Generation Loss = 246.5 MW
> Required reserve = 246.5 + 70 MW Spinning Reserve = 316.5 MW (~17%-18% reserve)

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[9] Spinning reserve is the extra generating capacity that is available by increasing the power output of generators that are already in operation and connected to the power system.

N-2 Contingency Involving Holyrood Unit 1or 2 and the Hardwoods or Stephenville Gas Turbine:
Generation Loss= 220 MW
Required reserve = 220 + 70 MW Spinning Reserve = 290 MW (~15%-16% reserve)

Past experience has proven that, in extreme situations, the IIS can be operated with as little as 20 MW of spinning reserve without having to resort to customer interruptions. Considering this, the N-2 contingency involving the loss of a unit at Holyrood and one of the 50 MW combustion turbines would be manageable with generation reserves as low as 240 MW.

As indicated in Table 3.2, system reserves will be greater than 240 MW (or approximately 13%) through the period 2014-2018. Because these reserves are based on a P90 load forecast in any given year, there is a 90% probability that actual reserves experienced will be greater than those reflected in Table 3.2. With reserves in the 250 to 300 MW range (as reflected in Table 3.2 through to 2018-19), the IIS will be capable of supplying all customer demand even under many of the potential multiple contingencies, and the risk of generation shortfall does not materially increase until reserves fall below 240 MW.

As a point of comparison, during the January, 2014 outage events, the IIS experienced unit de-ratings at an unprecedented five generating locations on January 2 and 3, 2014, with a total unavailability of 233 MW. If generation reserves had been in the 250 MW to 300 MW range at that time, the IIS would have been able to manage this level of unavailability without customer interruption.

To materially increase reliability on the IIS at this time it would be necessary to maintain reserves in the 350 MW to 400 MW range as reflected in the analysis above. This would require additional generating capacity almost immediately. Consistent with Liberty's comments on page 31 of their Report[10], Hydro believes there is no compelling reason to increase generating capacity unless: a) the load forecast increases; b) generation performance deteriorates; and/or c) there is a subsequent delay in the in-service date for the Muskrat Falls interconnections.

Hydro agrees with Liberty's recommendation 2.7, and on the basis of the above discussion and analysis of risk, Hydro concurs with Liberty that it is not necessary to stipulate a specific reserve number or percentage at this time. Continued diligence in maintaining and improving the reliability of existing generation assets will be Hydro's primary focus in reducing the risk of generation failures that could result in capacity shortfalls.

As well, consistent with Liberty's recommendation 2.7, Hydro proposes that in August of each year it will file an update with the PUB providing:

1. The updated P90 load forecast for the period up to one year beyond the then anticipated interconnection date.
2. A summary of the previous winter's generation performance and an outlook of peak available generating capacity for each year of the load forecast.
3. The forecast generation reserves both in percentage and total MW's.

In the event there are changes that result in the forecast reserve falling below 240 MW, Hydro will complete an assessment of the associated risks and report to the Board its recommended mitigations. In the interim, Hydro will continue to work with stakeholders to identify viable alternatives to increase capacity reserves should the need arise. Hydro will continue to maintain and update the Strategist[11] model of the IIS.

[10] Liberty concluded that "given the addition of significant new capacity with Muskrat Falls in the near future there is little need to add new generation now although reserves are still low".

[11] Strategist is an integrated resource planning software application developed by Ventyx Inc.

Quarterly Reporting – Generating Unit Performance

Hydro agrees with Liberty's recommendation 2.8 and will report quarterly to the Board on the rolling 12 month performance of its generating units.

Outlook for Supply Adequacy

Hydro agrees with Liberty recommendation 2.9 and will promptly report to the Board any potential change in the adequacy of supply, including increases in forecasted peaks or sustained reduction in unit availabilities. As noted in the above discussion on reserve margins, Hydro will do this on a planned basis in August of each year by submitting an updated P90 weather forecast and projected reserve margins. With its Strategist model, Hydro will also model changes in generation performance or availability and will be able to assess the relative impact of any decreases in availability or sustained unit de-ratings on overall system reliability. Hydro will report the impact of any changes in the annual update and if necessary recommend mitigative measures. In the event that unanticipated factors during the year result in an immediate change in the supply adequacy outlook, Hydro will update the Board at that time.

3.1.2 Operations Load Forecasting

3.1.2.1 Actions Taken By Hydro

In addition to the load forecasting completed by Hydro for long term power supply planning, the Company regularly forecasts loads for medium and short-term operations planning purposes. As part of its internal review and investigation of the events of January, 2014 Hydro engaged Ventyx to complete an independent, expert review of its load forecasting processes. Ventyx confirmed that Hydro's forecasting processes were consistent with accepted utility standards.

The Ventyx review also verified that Hydro's medium term and short-term seven day operating load forecasts did not lead to decisions that contributed to the rotating outages on January 2 and 3, 2014. Hydro's inability to meet the full system load on these days was related to the unavailability of sufficient generation (i.e., power supply).

Ventyx did recommend that enhancements be made to both Hydro's medium and long term load forecasting models to incorporate sensitivity testing for alternative load forecasts related to different extreme weather scenarios. Hydro adopted this recommendation as part of its 2014 IAP and has included P90 weather sensitivities as part of both its medium and long term forecasts.

The Ventyx review of Hydro's short term seven day load forecasting program (Nostradamus) highlighted that the temperatures experienced in mid December 2013 and early January 2014 were highly atypical and therefore not well represented within the model's historic dataset. This resulted in short term daily forecasts that were not always well correlated with actual load. This had no impact on the January 2014 system events, but more accurate daily load forecasts could have improved the prediction and communication of the impact of the generation outages on Hydro's ability to supply customers, to both internal and external stakeholders, including Newfoundland Power and the general public.

In its report to the Board on October 31, 2014 *(Progress Report on Load Forecasting Improvements)* Hydro provided a detailed update on the work completed by Hydro in its review of all load forecasting processes – short-term; medium term; and long term. This update included the following:

a) A description of the various modifications made to Nostradamus and its supporting database to improve the accuracy of short-term load forecasts;
b) A status update on Hydro's analysis of system losses associated with different generation configurations and transmission contingencies, and the methodology being used for this analysis;
c) The results of Hydro's efforts to re-construct the peak load on January 2, 2014;
d) Hydro's analysis of the winter 2013/14 weather conditions and their contribution to the peak load exceedances which occurred relative to the forecasted winter peak; and,

e) The results of Hydro's review of the recommendation by Ventyx that increased sensitivity analysis be incorporated into its long term generation planning process, in particular the use of a P90 peak weather assumption.

3.1.2.2 Recommendations by Liberty Consulting

Table 3.4 below identifies Liberty's conclusions and recommendations related to load forecasting.

Hydro acknowledges and agrees with Liberty's conclusions 2.1, 2.2 and 2.8 indicating that considerable progress was made by Hydro in 2014 in relation to its load forecasting processes, and also agrees with conclusion 2.4. As discussed in section 3.1.1.2 above, Hydro is also in agreement with Liberty's conclusion 2.5 and their view that Hydro's current load forecasting approach gives appropriate visibility to the P90 forecast criterion.

TABLE 3.4
LIBERTY'S CONCLUSIONS & RECOMMENDATIONS – LOAD FORECASTING

RELATED CONCLUSION(S)	RECOMMENDATION	
Hydro has made major improvements in its load forecasting capabilities as they apply to supply planning (2.1). Improvements to the short-term operating forecasts have also been made, but have not yet been fully proven (2.2).	2.1	Provide the Board with monthly updates on the status of Nostradamus upgrades until the production model is fully in-service and shaken down.
	2.2	By April 30, 2015, provide the Board an assessment of the effectiveness of Nostradamus during the 2014-15 winter and the sufficiency of the model for continued future use.
Hydro has made significant improvement in relating transmission losses to generation configurations, but has yet to complete the effort (2.3).	2.3	Provide the Board with the guide on system losses under various configurations and any instructions for their use.
Hydro has implemented the change to load reporting on an IIS basis, as recommended (2.4).		
Liberty continues to consider the P90 forecast as the preferred planning base (2.5).	2.5	By March 1, 2015, provide data relating the actual values of the weather variable on the 2013-14 winter days on which the annual peak forecast was exceeded.

Table 3.4 **Liberty's Conclusions & Recommendations – Load Forecasting**		
Related Conclusion(s)	**Recommendation**	
Hydro's conclusion that weather caused actual peak load to exceed the forecasted annual peak forecasted in all four months of the 2013-14 winter warrants further support (2.6). Hydro's reconstruction of its peak loads to account for conditions that can make it artificially low is not convincing (2.7).	2.6	By March 1, 2015: (1) clarify Hydro's proposed reconstruction of the winter 2013-14 peak, (2) provide a specific value for the reconstructed peak, and (3) report on the impact of the reconstructed peak on the analysis of 2013-14 forecast exceedances.
Hydro implemented a number of load forecasting process improvements during 2014 (2.8).		

Short Term Load Forecasting Updates

Hydro's upgraded version of the Nostradamus application used for short term load forecasting went into production in late November, 2014 and its effectiveness has been continually assessed since that time. Liberty's conclusion 2.2 that improvements made to Hydro's short-term operating forecasts have not been fully proven is accurate given the chronological proximity of Liberty's report (December 17, 2014) relative to the in-service date of the upgraded Nostradamus application, and considering as well that a complete assessment of effectiveness will not be known until the end of the 2014-15 winter season.

Hydro agrees with Liberty recommendation 2.1. Minor adjustments have been made to Nostradamus since November to improve its short-term predictive abilities based on real-time experience, and effectively the Nostradamus model is now fully in-service. Hydro filed its latest update on the accuracy of Nostradamus load forecasting with the Board on January 30 for the month ending December 31, 2014. These reports will continue at least until the end of the 2014/15 winter season, so that Nostradamus' effectiveness can be fully evaluated.

Hydro intends to evaluate its experience with the upgraded version of Nostradamus following the end of the 2014/15 winter season. Hydro agrees with Liberty's recommendation 2.2 and the required report will be provided to the Board by no later than April 30, 2015.

System Losses Under Various Configurations

During the system events of January, 2014 Hydro experienced incremental system losses of between 30MW and 40 MW due to the fact that the Avalon Peninsula, the island's highest load centre, was being served by generation located off the peninsula (i.e., Bay d'Espoir). Hydro adopted a recommendation made by Liberty in their Interim Report that load variations resulting from different system configurations be incorporated into the Company's short term forecasting process to provide guidance to Energy Control Centre (ECC) Operators under abnormal conditions.

With respect to Liberty's conclusion 2.3, Hydro has completed this analysis which incorporates a consideration of different generation configurations and various transmission system contingencies, and is now applying the results. Hydro agrees with Liberty's recommendation 2.3 and will supply the Board with its guide on system losses by March 1, 2015 as recommended.

Exceedances of the Annual Peak Weather Forecast for Winter 2013/14

Hydro agrees with Liberty's recommendation 2.5 and the requested data for both the Hydro system and the total IIS will be provided to the Board by March 1, 2015.

Analysis and Reconstruction of Peak Loads for Winter 2013-14

Actual peak load in each of the four months of the 2013/14 winter period exceeded Hydro's annual winter peak forecast. As Liberty noted in their Report, this was highly unusual and unexpected relative to Hydro's experience over the prior 10 winter seasons, when only one material exceedance was experienced. In order to determine if there were any factors that were common to these exceedances in 2013/14 and to identify any related opportunities for improving its load forecasts, Hydro evaluated the 2013/14 winter days on which peak load exceeded the annual (winter) peak forecast. In this process, Hydro also attempted to reconstruct the actual peak load on January 2, 2014 when rotating outages were first initiated. In addition, Hydro evaluated whether any peak loads may have been artificially affected (inflated) to any significant degree by factors such as customer notifications issued under the Company's Generation Shortage Protocol.

As noted earlier, Hydro's progress in these areas was reported to the Board on October 31, 2014. Regarding Liberty's conclusions 2.6 and 2.7, Hydro believes that its analysis of peak exceedances and its reconstruction of peak load on January 2, 2014 were supportive of its conclusion that extreme weather was the only common factor explaining the peak loads experienced over the 2013/14 winter period.

However, Hydro recognizes the importance of the underlying question as to what factors may have had a material impact on peak load, and agrees that more analysis would be helpful. On that basis, Hydro agrees with Liberty recommendations 2.5 and 2.6, and the additional analyses these recommendations require will be submitted to the Board by March 1, 2015.

3.2 Generation Supply and Availability

3.2.1 Power Supply

3.2.1.1 Actions Taken by Hydro

As noted earlier, Hydro's most recent generation planning analysis prior to 2014 was completed in late 2012. This analysis projected a capacity deficit occurring in 2015 and it recommended the addition of a 50 MW combustion turbine by December 2015 as the least cost solution for mitigating the anticipated deficit. The 2012 recommendation recognized that during early 2015, and prior to the installation of the combustion turbine, the Loss of Load Hours (LOLH) on the IIS would in fact be higher than the 2.8 hour planning threshold.

While completing its internal review of the January, 2014 system events Hydro reviewed its capacity planning options to ensure that a combustion turbine was still the best option, and to identify means to fully mitigate the forecasted 2015 deficit. Other options placed under consideration included the following, with a combination of two or more options being a further possible option:

a) Retain the diesel facility then being installed at Holyrood for blackstart capability (10 MW on a sustained basis with the potential for 14.6 MW with modifications).
b) Enter into interruptible contracts with large Industrial Customers.
c) Seek already built combustion turbines in the 50 to 100 MW range to supply deficit and blackstart at Holyrood. Discussions with manufacturers, brokers and owners were ongoing at the time to determine availabilities, delivery times, operating experiences, and the extent of modifications and facilities required to connect to the Island Interconnected System.
d) Initiate the supply of a new combustion turbine for the Holyrood site to supply deficit and blackstart functionality based on the engineering and other work already completed for the planned capacity addition in late 2015.
e) Continue and enhance conservation and demand management initiatives, with a focus on demand management. This was considered a supplemental means of meeting the anticipated deficit.

As Hydro advanced its evaluation of these alternatives, options b) and c) above were identified as being the most beneficial and feasible in terms of meeting the power supply needs of the IIS leading up to interconnection and the in-service of Muskrat Falls, including the coming 2014/15 winter season. As Liberty noted in their Report, Hydro made very significant progress in 2014 in adding new generation capacity and in securing capacity assistance arrangements with its largest industrial customers. The actions taken in both areas have added approximately 200 MW to Hydro's available power supply.

3.2.1.2 Recommendations by Liberty Consulting

Table 3.5 below identifies Liberty's conclusions and recommendations related to power supply.

TABLE 3.5
LIBERTY'S CONCLUSIONS & RECOMMENDATIONS – POWER SUPPLY

RELATED CONCLUSION(S)	RECOMMENDATION	
Despite nearly 200 MW of additional generation and demand-side resources, the supply situation is expected to remain tight until the arrival of Muskrat Falls (2.9).		
Additional new generation does not present a good option, unless new load materializes or availability declines (2.10).		
The new CT is urgently needed for this winter and must be expedited into service as quickly as possible (2.12).	2.10	Continue to treat completion of the new CT as soon as possible a high priority for Hydro management, supported by close executive attention.
Securing arrangements for 75 MW (including one for 15 MW in the process of finalization) in recent months reflects a successful effort to secure interruptible load (2.13).		
Conservation and Demand Management Programs have focused on cost-effective energy reductions; the focus needs to expand to include demand reductions (2.21). History suggests that Hydro will consult with Newfoundland Power on the design and results of the coming analyses related to conservation and demand management, but it is not clear that Newfoundland Power will share "ownership" of the process (2.22).	2.16	Complete planned demand management analysis on a Hydro/Newfoundland Power jointly scoped, conducted, and developed basis and report to the Board a structured cost/benefit analysis of short term program alternatives by September 15, 2015.

New Generation Capacity

In March, 2014 Hydro aggressively initiated a search focused on sourcing an already built combustion turbine capable of supplying 50-100 MW of standby peaking power. Several options were identified and Hydro later initiated a public tender for a 100 MW combustion turbine to be installed by December, 2014. Through this process a new, unused turbine with a capacity of 123.5 MW was secured. All activities associated with verifying the unit's condition and fitness for purpose; finalizing commercial arrangements; and completing all necessary planning and engineering work were fast-tracked. Site clearing at Holyrood began on June 9, 2014 and the first components of the new unit arrived on site on August 13, 2014.

On January 21, 2015 the commissioning of this new CT had advanced to the point where it was successfully tested up to a load of 40 MW and synchronized to the IIS. Over the following days the CT was successfully tested at higher loads of 60 MW, 80 MW, and 100 MW in a controlled step-up manner. Final commissioning is continuing and is near completion, after which the unit will be fully available for dispatch in support of the IIS as required. Although final commissioning of the new CT is not complete, this unit has been available for power generation on an emergency basis since January 21, 2015. Hydro provided its most recent status update on this project to the Board on January 30, 2015.

Completion of the new CT in time to provide standby support during the 2014/15 winter season has been a steady focus for Hydro. Consistent with Liberty's recommendation 2.10, with which Hydro agrees, the new CT continues to be the subject of daily updates to the CEO and other members of Hydro's executive team. While timely completion is an obvious priority, Hydro's first priority is to ensure that the necessary work is completed safely and correctly so as to avoid any risks to the unit's long term reliability.

Otherwise, Hydro agrees that the new CT is required for the 2014/15 winter season consistent with Liberty's conclusion 2.12, and Hydro's priority focus regarding the acquisition of new generating capacity is evident in the action it took to acquire and install a new CT in time for the 2014/15 winter season.

Securing Interruptible Load

Hydro acknowledges Liberty's conclusion 2.13 that Hydro's efforts in 2014 to secure interruptible load were successful. Late in 2014, Hydro concluded a further arrangement with Corner Brook Pulp and Paper (CBPP) under which Hydro can access up to an additional

20 MW of capacity assistance on a net basis if needed, thus bringing the total amount of capacity assistance available from CBPP and Vale to approximately 91 MW in 2014/15 (increasing to 96 MW in 2015/16)[12].

Power Supply Leading up to Interconnection

The forecast of power demand and supply on the IIS over the next several winter periods as shown in Table 3.2 indicates reserve margins of between 19.1% in 2014/15 and 13.4% in 2017/18 under a P90 load forecast scenario. Because the latter calculation assumes first power from Muskrat Falls is not available over any part of the 2017/18 winter period, this analysis effectively predicts a reserve margin of 13.4% or higher until at least November, 2018.

With respect to Liberty's conclusion 2.9, Hydro is confident that the power supply it has added through the new CT and its capacity assistance agreements, combined with a strong focus on both the ongoing performance reliability of its assets and the potential for load reductions through short term demand management initiatives, will ensure reliability of power supply until the in-service of Muskrat Falls. In addition, as outlined in section 3.1.1.2, Hydro has committed to at least annual updates of its generation planning load forecasts to ensure that decisions regarding additional generating capacity, if required, can be triggered in a timely manner. Hydro agrees with Liberty's conclusion 2.10, and the emphasis they place in their report on the need for continuing and constant monitoring of asset performance and reliability is consistent with Hydro's approach to ensuring adequate power supply.

[12] The supplemental capacity assistance agreement with Corner Brook Pulp and Paper provides for up 30 MW on a gross basis, but this includes 8 MW of co-generation which is included in Hydro's available capacity. Hydro assumes a net availability of 20 MW, for a total of 80 MW from Corner Brook Pulp and Paper. The amount of capacity assistance from Vale in 2014/14 is 11 MW, increasing to 16 MW in 2015/16.

Short Term Demand Management Options

Hydro agrees with Liberty's conclusions 2.21 and 2.22 and with Liberty's recommendation 2.16 that Hydro and Newfoundland Power jointly complete a demand management analysis, and report to the Board on a structured cost/benefit analysis of short term program alternatives. The availability of feasible and cost-effective options for driving demand reduction between 2015 and the in-service of Muskrat Falls in 2017/18 may be limited, but Hydro is committed to creatively exploring all possibilities. It is possible as well that this review may identify demand management options that may be justified on a net cost/benefit basis in the longer-term.

Hydro and Newfoundland Power collaborate often on different levels. Several current CDM programs in the province are jointly sponsored by Hydro and Newfoundland Power, and are the product of extensive collaboration and consultation between the two utilities. The two companies consulted extensively in 2014 on several joint projects flowing from the outage events of January, 2014, with good success. Regarding Liberty's conclusion 2.22, Hydro believes the two utilities share a common interest in leveraging demand reduction opportunities which make sense from a cost and value standpoint for rate payers. As noted in its response to GRK-NLH-082, Hydro agrees with the principle of working in partnership with Newfoundland Power to develop conservation and demand management plans, but owing to the distinct function that each utility performs in supplying power and energy to the IIS, there are particular aspects of the planning of CDM in which each utility naturally takes a leadership role.

3.2.2 Generation Availability

3.2.2.1 Actions Taken by Hydro

The outages experienced in January, 2014 were precipitated by unplanned reductions in generation availability at five different generating facilities occurring late in 2013. This situation was exacerbated in the following days by a breaker problem in the Holyrood switchyard preventing Unit #1 from being restored. These events highlighted a clear need to focus in 2014 on ensuring and improving the reliability of Hydro's generation assets, in particular its thermal generation units. Several actions were incorporated into Hydro's 2014 IAP with this purpose in mind, and as Liberty confirm in their report, an extensive amount of capital work and incremental maintenance was completed in 2014 over and above Hydro's planned annual workplan (see IAP#12, 12a, 12b, 12c, 13, 16 and 17).

Hydro's *Generation Master Plan for Winter Preparation* integrated both the incremental maintenance activities planned under its IAP as well as all of the planned 2014 capital projects that were concerned with generation reliability.

A standard process used by Hydro to plan and track the execution of maintenance work is its Annual Work Plan (AWP). The AWP integrates all planned activities for the year related to the corrective maintenance, preventive maintenance, and capital project support which are critical to safe, reliable production. Work orders generated during the year as a result of planned inspections or ongoing monitoring are also integrated into the AWP as appropriate. In 2014, the AWP exceeded the original plan to ensure a strong focus on winter readiness.

Hydro regularly measured the progress of AWP execution in comparison with plan, and was able to track AWP status down to the level of individual work plan items. As reported to the Board on January 15, 2015 Hydro executed 100% of the 2014 work required for safe and reliable winter production at both Holyrood and in its hydraulic operations, and 96% of the combined AWP for its gas turbines (98% at Hardwoods, 94% at Stephenville). The AWP items not completed in 2014 for the CTs were all related to protection and control and were not essential to winter generation availability.

As of December 1, 2014 all of Hydro's generating units, with the exception of the new CT at Holyrood, were available to the IIS. At different points in December and January, Hydro experienced some de-ratings at Hardwoods and Stephenville primarily associated with engine fuel lines and fuel control valve issues. However, these have since been resolved.

3.2.2.2 Recommendations by Liberty Consulting

Table 3.6 below identifies Liberty's conclusions and recommendations related to generation availability and reliability.

Table 3.6
Liberty's Conclusions & Recommendations - Generation Availability

Related Conclusion(s)	Recommendation	
Despite improvement initiatives in 2014, availability remains a major challenge (2.11).		
Hydro's application of color coding is not fully meeting the Board's requirements in seeking reports, nor does that application serve to give Hydro management early warning of matters that may require its intervention (2.14).	2.11	Establish and use a more effective system of reporting and analyzing status to give Hydro management early warning and the opportunity for intervention.
	2.12	In all reports to the Board, provide, and adhere to, a clear definition of reporting practices, including the definition of classifications (such as colors) used to categorize performance status
Maintenance initiatives during 2014 have been generally successful (2.15). Despite substantial progress in addressing winter readiness, lingering problems with Hydro's existing CTs pose supply adequacy threats this winter (2.16).	2.13	Given the vulnerabilities likely to be present on December 1, 2014, Hydro must take at least the following actions immediately: a) Prepare an emergency contingency plan to identify all generation resources for a potential supply emergency while the new CT remains unavailable. b) Report to the Board all steps being taken to expedite completion of the new CT. c) Be prepared to trigger emergency plans when and if extreme weather sufficient to reach or exceed expected peaks is forecast. d) Report to the Board daily whenever forecasted reserves for the day are less than 10 percent. e) Report to the Board immediately whenever forecast reserves fall under 10 percent during any day.
	2.14	Continue to rely on the old CTs for reliable capacity and continue to focus on steps to improve their availability.

TABLE 3.6 **LIBERTY'S CONCLUSIONS & RECOMMENDATIONS - GENERATION AVAILABILITY**		
RELATED CONCLUSION(S)	**RECOMMENDATION**	
Hydro has made progress in completing planned 2014 capital projects at its generating units (2.17).		
While progress has been made in assessing parts criticality for generating units, Hydro has yet to complete the procurement of critical spares (2.18).	2.15	Report to the Board by February 15, 2015, the final status of the program for critical spares, its results versus expectations of the master plan, a listing of spares to be procured, and when they will be available.
Hydro has made reasonable progress in structuring and executing a winter readiness plan and should continue to develop its acceptance and use (2.19).		
Liberty found field execution of the asset management program in 2014 to be sound, recognizing, however, that uncertainties about certain generating units remain (2.20).		

Generation Winter Readiness and Availability

Hydro acknowledges and agrees with Liberty's conclusions 2.15, 2.17, 2.19, and 2.20. With respect to conclusion 2.11 Hydro acknowledges that the reliability of generating equipment must continue to be a critical focus area. The discussion on pages 25-27 in Liberty's Report adds to the summary provided above in section 3.2.2.1, and verifies the extensive work completed by Hydro in 2014 to ensure the reliability and winter readiness of its generation assets. While there were issues related to engine fuel lines with the existing CTs beyond December 1, 2014 (which have since been resolved as noted earlier), Hydro entered the 2014/15 winter season with its people and equipment well prepared to provide sustained, safe and reliable performance from its generating facilities.

Hydro's experience with its gas turbines at Hardwoods and Stephenville in December and January supports Liberty's conclusion 2.16 as it was stated at the time of their Report. Hydro acknowledges there were some continuing issues affecting the availability of these facilities at different points between mid-December and January 29, 2015. However, considering the related nature of the issues at both facilities (related to engine fuel lines and control valves), as well as the performance of these units since repairs were completed, Hydro feels these units will continue to be available on a sustained basis for peak load support for the remainder of the 2014/15 winter period. In the meantime, Hydro plans to continue its focus on implementing the maintenance and capital programs required to ensure that the CTs continue to be available for peak load capacity support, consistent with Liberty's recommendation 2.14, with which Hydro agrees.

Hydro agrees with, and has implemented, all elements of Liberty's recommendation 2.13. In a letter to the Board on December 23, 2014 Hydro reported on the actions being taken to expedite completion of the new CT, as well as the status of all generation sources that were available in the event of a power supply emergency while the new CT was unavailable. The Board was advised as well that recommendations 2.13(c), (d), and (e) were being met through already existing reporting processes.

Critical Spares

Hydro agrees with Liberty's conclusion 2.18 and its related recommendation 2.15. As Liberty note in their Report, Hydro completed extensive reviews of its critical spares requirements in 2014 in all three areas of its generation operations – Holyrood; hydraulic generation; and its gas turbines. Plans to procure critical spares not currently in inventory were initiated and, in most cases, were procured in advance of the 2014/15 winter season. Other critical spares requiring longer lead times have been placed in inventory as they have arrived.

A key critical spare identified through Hydro's review of its requirements at Holyrood was 4 kV motors. There are a number of motors in this voltage class that are used in different stages of the operation of the Holyrood generating units, and Hydro's analysis highlighted Forced Draft (FD) fan motors and Boiler Feed pump motors as being particularly critical to generation reliability. The procurement of four spare 4 kV motors, at an estimated cost of approximately $500,000, was initiated and Board approval was sought. Hydro's orders were confirmed following approval by the Board in late November, 2014.

Hydro's assessment of its critical spares readiness for the 2014/15 winter season was reported to the Board on December 9, 2014. This report indicated a very limited number of potential critical spares risks associated with spares requiring a lead time of 10 weeks or more and, that otherwise, there were no significant reliability risks related to critical spares foreseen for the 2014/15 winter period.

Hydro will provide the Board with a final critical spares update on February 15, 2015 in line with Liberty's recommendation 2.15.

Management and Board Reporting

Several reporting processes were used in 2014 to assist in the tracking and reporting of Hydro's progress in the execution of outage-related action plans and capital projects. Some of these were existing processes at Hydro, while others were newly developed for the purposes of reports and periodic updates to the Board. Copies of each of these are available on the Board's web site.

a) **IAP Tracker and Summary Dashboard**: This was a matrix format planning and tracking tool used for both internal management reporting and Board updates. The IAP identified specific actions/deliverables; the Hydro personnel accountable and responsible for completion (not shown in the Board updates); expected completion dates; status comments; and overall status.

b) **AWP Tracker**: A visual bar graph presentation showing the year-to-date completion status of planned activities (vertical line) compared with plan (horizontal bar). This graph was complemented by a text box which provided summary details; recovery plan information for delayed items; and an overall year-end outlook.

c) **Incremental Capital Project Updates**: Bi-weekly updates were provided to the Board on the new Holyrood CT; the transformer replacement at Sunnyside; and the transformer refurbishment at Western Avalon. These updates included a status view of the high level project plan (Gantt format); cost and man-hour S curves (indicating cost and man hours expended versus plan); an overview of identified project risks and related mitigation strategies; and a high level color-coded indication of overall status relative to safety; schedule; cost; and quality.

d) **2014 Capital Plan Updates**: Monthly updates were provided to the Board regarding the execution status of Hydro's 2014 capital plan. These updates indicated expected completion versus plan (number of projects); details on projects where substantial completion in 2014 was not expected; and cost S curves indicating year-to-date spend versus budget.

e) **Winter Generation Master Plan for Winter Preparation**: This matrix format tool was developed to document and track the execution of this Plan. This report itemized key maintenance activities as well as reliability-related capital projects for each area of generation operations; expected completion dates; and a color-coded indication of completion status. Notes were also provided at the bottom of the matrix table to elaborate on delayed or yet to be competed projects as appropriate.

Liberty's conclusion 2.14 addresses two aspects of progress reporting: a) status reporting to the Board, and b) internal management reporting.

Hydro is not able to either agree or disagree with Liberty's conclusion 2.14 regarding the formats it used for reporting purposes to the Board. The format for regular status reporting on Hydro's incremental and planned capital projects; Hydro's AWP; and the 2014 IAP were refined and adjusted based on discussions with the Board and with Liberty.

Hydro acknowledges that some confusion may have existed in relation to Hydro's use of color code indicators. Hydro's customary use of Green is to indicate an expectation that an activity or project will be completed on schedule (e.g., by year-end), even if one or more related milestone activities are behind schedule. In fact many of Hydro's internal reporting processes use two color code indicators – one to indicate the outlook for completion as planned, and another to indicate the current status versus plan. This is a system which ensures that management focus is prioritized around the right issues, as indicated by a Red code for example, but at the same time indicates caution and the need for a recovery plan and revised dates if necessary on any delayed activities. Hydro agrees with Liberty's recommendation 2.12 as it relates to reporting to the Board, and this will be an aspect of Hydro's consultation with the Board regarding their needs and requirements. Hydro is fully committed to providing the Board with the information it determines it requires in a format that is acceptable and useful to the Board.

In their Report Liberty references Hydro's status reporting on the new CT to support their view that Hydro's was late in indicating a status change in schedule for that project. Hydro changed the schedule status of this project from Green to Yellow in early November which, in the context of Hydro's use of color codes as noted above, was prudent timing in Hydro's opinion. It should be remembered that the schedule for this project was highly fast-tracked with no built-in schedule "float", thus Hydro was managing schedule risks aggressively and continuously. Up to the end of October, with all of the mitigation strategies that were planned, Hydro continued to expect that the CT would be completed in December as planned. However, when it became apparent there was a risk to that schedule, the schedule status was changed to Yellow, and the Board was advised accordingly.

Both the Board updates and Hydro's internal reporting processes served to ensure that operations and executive management personnel were fully informed and up to date.

Hydro regularly reviews it management processes for improvement opportunities, and the management reporting processes noted above will be reviewed in 2015 consistent with Liberty's recommendation 2.11, and revised as appropriate.

4 ASSET MANAGEMENT PROGRAMMATIC ASPECTS

Hydro acknowledges and agrees with Liberty's conclusion 3.1 that the design and scope of Hydro's asset management program is sound and conforms to best practices.

5 TRANSMISSION AND DISTRIBUTION DESIGN

5.1 Planning and Project Prioritization

Table 5.1 below identifies Liberty's conclusions and recommendations related to transmission and distribution system planning, and project prioritization.

TABLE 5.1
LIBERTY'S CONCLUSIONS & RECOMMENDATIONS - T&D SYSTEM PLANNING & PROJECT PRIORITIZATION

RELATED CONCLUSION(S)	RECOMMENDATION	
Hydro does not compare cost with projected avoidance of customer interruption numbers or minutes in prioritizing distribution upgrade projects (4.7).	4.3	When prioritizing reliability projects, include a factor that relates cost to anticipated avoided customer interruption numbers and minutes.
Despite a structured process for prioritizing projects, it is not clear that Hydro sufficiently emphasizes SAIFI and SAIDI (4.8).	4.4	Increase the weighting given to resulting SAIFI, SAIDI, and numbers of customer interruptions and minutes when prioritizing proposed project.
Hydro plans its transmission and distribution systems for load growth and other technical constraints on an appropriate basis (4.9). Hydro's distribution system planning criteria are also consistent with good utility practices (4.10). Hydro's load flow, voltage, stability, interconnection, and short circuit studies are appropriate and consistent with good utility practices (4.11). Hydro's Distribution Planning group provides those technical studies required to support the Transmission and Rural Operation staff (4.12). Hydro has built its transmission lines and distribution feeders in excess of Canadian Standards Association (CSA) Overhead Systems criteria and in conformity with good utility practice (4.16).		

TABLE 5.1 **LIBERTY'S CONCLUSIONS & RECOMMENDATIONS - T&D SYSTEM PLANNING & PROJECT PRIORITIZATION**		
RELATED CONCLUSION(S)	**RECOMMENDATION**	
Hydro uses IEEE Standard transmission and distribution conductor and transformer capacities for planning and operating its electric systems, which conforms to good utility practices (4.17). Hydro allows limited temporary overloading of its transmission lines and its terminal station transformers, but limiting the "hot spot" temperature to 110°C appears to be unduly conservative (4.18). Practices for transmission system raptor protection, lightning protection, and galloping conductor prevention have conformed to good utility practices (4.21).		

5.1.1 Hydro's Project Planning Criteria

Hydro's established process for prioritizing capital projects uses both quantitative and qualitative criteria, and follows a two tiered approach. Consideration is first given to any projects that are required to correct an extreme safety issue, to meet mandatory demands (e.g., legislative), or to satisfy reliability-related system load growth requirements. If any of these three factors exists the project is considered high priority and is placed at the top of the prioritization list. All other projects are assigned to the second tier and are assessed against 12 criteria, each of which is assigned a point value. These values collectively add up to 1,000. A number of factors are identified for each criterion and are assigned a weighting relative to the maximum weighting of the criterion.

Two of the 12 assessment criteria specifically address customer impacts.

1) Continue Service to Customers
    a. Service to customers can continue without the project
    b. Service to customers can continue but with high costs
    c. Service to customers cannot continue without the project

2) Number of customers impacted
    a. The project will impact (benefit) up to 100 customers
    b. The project will impact up to 1,000 customers
    c. The project will impact up to 10,000 customers
    d. The project will impact more than 10,000 customers

Four other criteria are not customer-specific, but they address system impacts from a reliability, duration, and loss of facilities standpoint, and are therefore relevant from a customer impact standpoint.

3) System impact
    a. The project is not critical to any particular system.
    b. The project is critical to a system, but a standby unit can be used to maintain operation or support in the event of failure.
    c. The project is critical to the proper operation of a generating plant or a terminal station.
    d. The project is critical to ensure the reliable operation of the Hydro system.

4) Impact Intensity
    a. Minor - If this project does not proceed, the repair time is *less than half* the Maximum Acceptable Downtime (MAD) of 830 MWh of unsupplied energy or two days (whichever comes first).
    b. Moderate - If this project does not proceed, the repair time is *greater than the half but less than 90%* of the Maximum Acceptable Downtime (MAD) of 830 MWh of unsupplied energy or 2 days (whichever comes first).
    c. Significant - If this project does not proceed, the repair time is *within plus or minus 10%* of the Maximum Acceptable Downtime (MAD) of 830 MWh of unsupplied energy or 2 days (whichever comes first)
    d. High - If this project does not proceed, the repair time *exceeds by more than 10%* the Maximum Acceptable Downtime (MAD) of 830 MWh of unsupplied energy or 2 days (whichever comes first).

5) Loss Type
    a. No type
    b. Equipment …
    c. Facility …
    d. Production – If the project does not proceed, there exists a risk of the loss of production at a Hydro generating plant.
    e. Customer Delivery – If the project does not proceed, there exists a risk of being unable to deliver power to Hydro customer(s).

6) Loss Mitigation
    a. Redundant unit - If the project does not proceed the expected loss will be mitigated by a redundant unit present on the system.
    b. Back-Up Option - If the project does not proceed the expected loss will be mitigated by a back-up option which ensures that service continues.
    c. Nothing - This project is required because there is no available means to mitigate the expected loss.

The six criteria noted above collectively account for 47% of the total weight assigned to the 12 assessment criteria. Included in the remaining criteria are factors that address the safety and environmental aspects of capital projects (with a combined weighting of 20%), as well as criteria that evaluate the payback period and net present value from a cost/benefit perspective (a combined weighting of 17%).

5.1.2 Recommendations by Liberty Consulting

Hydro acknowledges and agrees with Liberty's conclusions 4.9, 4.10, 4.11, 4.12, 4.16, 4.17, 4.18, and 4.21. Collectively, these conclusions confirm that Hydro's standards, practices and processes related to the planning and design of its transmission and distribution systems are in conformance with good utility practice.

Liberty's conclusions 4.7 and 4.8, and the associated recommendations 4.3 and 4.4, speak to the manner in which the frequency and duration of customer interruptions are considered in the prioritization of transmission and distribution projects. As discussed above in section 5.1.1, customer impacts are considered in Hydro's project ranking process to a significant extent. However, Hydro acknowledges that customer interruption frequencies and durations and SAIFI and SAIDI are not specifically incorporated into the assessment. On this basis, Hydro agrees with Liberty's conclusions 4.7 and 4.8 and with recommendations 4.3 and 4.4. Hydro will adopt these recommendations and will review its capital project ranking process in 2015 with these considerations in mind.

With respect to Liberty's conclusion 4.18, Hydro will incorporate a review of its practices regarding its current limitations on "hot spot" temperatures into its 2015 workplan.

5.2 Transmission and Distribution Availability

Table 5.2 below identifies Liberty's conclusions and recommendations related to transmission and distribution availability.

TABLE 5.2
LIBERTY'S CONCLUSIONS & RECOMMENDATIONS – TRANSMISSION & DISTRIBUTION AVAILABILITY

RELATED CONCLUSION(S)	RECOMMENDATION	
Customers on the IIS experienced a greater number of lengthy interruptions because of planned transmission system maintenance than because of forced interruptions (4.1).	4.1	Investigate and report on methods that can reduce Planned T-SAIDI.
Transmission-forced outage frequencies and durations both increased from 2009 to 2013 (4.2). Distribution outage frequencies and durations have increased, but remain consistent with Canadian averages after adjustment for major events (4.3). Loss of supply and scheduled outages have been the largest contributors to outages (4.4). Connectors, switches, and insulators made the largest contribution to equipment caused outages (4.5).		
The lack of a focused worst-feeder program creates a gap in addressing reliability issues (4.6).	4.2	Analyze and report on the benefits of a dedicated capital program component dedicated to addressing the previous year's 10 to 15 percent worst performing feeders.

Table 5.2 **Liberty's Conclusions & Recommendations – Transmission & Distribution Availability**		
Related Conclusion(s)	**Recommendation**	
Studies show that all transmission lines, terminal station transformers, substation transformers, and distribution feeders should operate within the limits of applicable equipment or N-1 transformer contingency ratings during the winter 2014/2015 peak demand (4.13). Hydro reports that it has completed the transmission and distribution planning actions identified in its Integrated Action Plan (4.14). Some of Hydro's 138 kV transmission circuits and nearly all of its 66/69 kV transmission circuits on the Island Interconnected System are radial, causing customer outages for forced and planned circuit outages (4.15).		
Hydro does not have SCADA monitoring or control on three 66 kV transmission circuits and fourteen of its fifty-two terminal stations; it has SCADA control for only ten of its thirty-five distribution substations (4.20).	4.6	Conduct a structured analysis of expanding the SCADA system to include more and perhaps all distribution substations, in order to reduce customer minutes of interruption, and to reduce SAIDI.
Hydro's distribution lightning protection, its use of downstream reclosers, and its distribution power system studies were consistent with good utility practices. However Hydro does not install animal guards on its distribution substation or feeder equipment (4.23).	4.7	Apply animal guards at distribution substations when conducting maintenance work in the substations.
Hydro is currently updating its transmission Geographic Information System (GIS) data. Currently, its GIS, which contains all data related to its assets for its transmission system is only about 65 percent up to date. It should continue with updating not only its transmission equipment data, but also its distribution equipment data (4.24).		

Hydro acknowledges and agrees with Liberty conclusions 4.4, 4.5, 4.13, 4.14, 4.15, 4.20, 4.23, and 4.24. For the most part these are factual statements based on data and information supplied to Liberty during their site visits and through RFI responses.

5.2.1 Transmission Reliability

The independent review conducted by AMEC Americas during Hydro's internal review of the January, 2014 outage events confirmed that the design of Hydro's transmission network follows industry practices and provides a reliable and robust network. Hydro's performance on its bulk transmission system has historically compared very favorably with the national average as reported by the Canadian Electricity Association (CEA) benchmarks. Between 2004 and 2012 (the latest year for published results at the time of AMEC's review), and based on a five year rolling average, Hydro considerably outperformed comparable utilities represented in the CEA average in relation to 230 kV transformer and circuit breaker performance. For 230 kV transmission lines Hydro posted results that were more variable with some results above and others below the CEA averages.

Liberty's conclusions 4.1 and 4.2 relate to delivery point[13] outage frequencies and durations on Hydro's transmission system (T-SAIFI, T-SAIDI). These measures do not look at specific equipment performance such as a transmission lines, breakers or transformers such as that discussed above. Instead, they measure the ability to maintain a power supply to the distribution system or points of power delivery to Newfoundland Power or other customers.

Historical data support Liberty's conclusion 4.1 that planned transmission delivery point outage durations on the IIS have been higher than forced-outage durations. As Liberty state in their Report, this is not surprising given the additional and increasing effort required to maintain this aging infrastructure.

[13] Delivery point is the point of supply where the energy from the Transmission System is transferred to the Distribution System or the retail customer.

Liberty's conclusion 4.2 that Hydro's delivery point forced outage frequencies and durations have increased from to 2009 to 2013 is correct based on a discrete comparison of 2009 performance versus 2013 performance. However, as the Liberty Report indicates, there are significant variances from one year to the next in all 12 data sets (i.e., T-SAIFI and T-SAIDI for both planned and forced outages for two regions as well as Newfoundland Power Interconnections). For example, in seven cases forced outage performance improved over 2012 and 2013 compared with 2011. In two other cases performance was effectively stable over the four year period 2010-2013.

This being said, Hydro remains committed to ensuring a robust transmission network and will continue to focus on reducing both the incidence and duration of transmission forced and planned outages. As part of this effort and focus, Hydro agrees with Liberty's recommendation 4.1 and feels there would be merit to investigating if there are any approaches it does not currently utilize that might reduce planned outage T-SAIDI in particular. This action will be incorporated into Hydro's workplan for 2015.

5.2.2 Distribution Reliability

Outage frequencies and durations on Hydro's distribution systems are similarly difficult to summarize in terms of any consistent trends. Liberty's conclusion 4.3 indicates in part that SAIFI and SAIDI have increased between 2009 and 2013. However, a comparison of performance in the Central and Northern areas of the IIS shows that, in three of eight cases (i.e., SAIFI and SAIDI for both planned and forced outages in the Central and Northern areas), distribution performance was better in 2013 than in 2009 (versus the one case noted by Liberty)[14]. In one other case (forced outage SAIDI in the Central region), as noted by Liberty,

[14] The planned outage SAIFI data for the Northern and Central regions shown on Page 48 of Liberty's Report are incorrect, which appears due to a data transposition error. The planned outage SAIFI for Northern was 0.53 and 0.46 interruptions in 2009 and 2013 respectively. The planned outage SAIFI for Central was 0.88 interruptions and 0.14 interruptions in 2009 and 2013 respectively. See Hydro's response to PUB-NLH-339.

the anomalous increase to 6.7 days in 2013 was largely attributable to severe weather in November, 2013 which caused a 67 hour outage on the Bottom Waters distribution system. As well, performance in the prior two years (2012 and 2011) was significantly better than in 2009. In one other case (forced outage SAIFI in the Northern region), 2013 performance showed an improvement over 2012 and was only marginally below 2009 performance (2.2 interruptions per customer vs. 2.1 interruptions per customer). Hydro acknowledges that distribution performance is highly variable which is due to the relatively small customer base and the impact that a significant event can have on the results.

The age and condition of Hydro's transmission and distribution assets have been major factors in reliability performance over the last several years. In addition to its ongoing maintenance program, Hydro's continuing and significant re-investment in the renewal of its assets is a key pillar of its asset management strategy for improving transmission and distribution outage frequencies and durations over time.

5.2.3 Worst Performing feeders

Liberty note that, in their experience, many utilities conduct programs focused specifically on worst performing feeders, and that such programs often target a fixed percentage of the worst performing feeders to address each year. Liberty also note, however, that worst performance alone cannot justify spending on particular feeders.

Regarding Liberty's conclusion 4.6, Hydro reviews feeder performance annually as part of its capital planning process, and this includes a review of those feeders with the worst performance. However, the focus is not exclusively on performance metrics since there can be various, different factors that Hydro also assesses. Nonetheless, Hydro believes this is an item worth further review and accepts Liberty's recommendation 4.2, and in 2015 it will complete an analysis of the potential benefits of a worst feeder program of the type noted by Liberty.

5.2.4 Distribution Sub-Stations

As noted above, Hydro agrees with Liberty's conclusion 4.20, and as such Hydro accepts Liberty's recommendation 4.6. In 2015, Hydro will complete a structured analysis of the potential for reducing outage durations by expanding SCADA to more and perhaps all sub-stations as recommended.

Regarding Liberty's conclusion 4.23, Hydro acknowledges and agrees that it does not currently apply animal guards at its distribution sub-stations or on its feeder equipment. Although there have been some incidents involving raptor nests on overhead lines, Hydro's review of sub-station and feeder incidents over the five year period 2009-13 confirms there have been no incidents involving animals. For this reason, Hydro is not able to agree with Liberty's recommendation 4.7 at this time. Hydro wishes to take the opportunity to assess this measure from a reliability and cost standpoint, and to review prevailing practices at other comparable utilities in the process. Hydro will incorporate this review into its 2015 workplan.

5.3 Terminal Station Transformers

Table 5.3 below identifies Liberty's conclusions and recommendations related to terminal station transformers.

Liberty's conclusion 4.19 is correct with the important exception of the transformer configuration Hydro has in place to support the Holyrood-Western Avalon loop, which currently has the capacity to meet an N-2 contingency (i.e., the loss of two transformers). As the Board is aware, a 138 kV transformer in Holyrood was temporarily located to the Sunnyside terminal station in the Fall of 2014 while a new transformer was being manufactured to replace the transformer destroyed by fire on January 4, 2014. This new transformer has since been received, and is being put into service at Holyrood to restore the Holyrood-WAV loop to its original capacity.

TABLE 5.3
LIBERTY'S CONCLUSIONS & RECOMMENDATIONS – TERMINAL STATION TRANSFORMERS

RELATED CONCLUSION(S)	RECOMMENDATION	
Hydro has incorporated redundancy (N-1 contingency) in its transmission lines and terminal station buses consistent with the needs of the system. Rather than maintaining a spare 125 MVA transformer, it however depends on its N-1 transformer contingency designs to maintain system loads in case of a transformer failure (4.19).	4.5	Perform a structured analysis of the costs and benefits of maintaining a spare for the 125 MVA transformers, considering age and equipment condition and the recent failures of the T1 transformer at Sunnyside Terminal Station and the T5 Transformer at Western Avalon Terminal Station.
Few Hydro distribution substations have multiple transformers and only some of the feeders can be tied to other feeders, which typifies rural distribution systems in our experience (4.22).		

Hydro's experience is that planning the deployment of power transformers based on an N-1 contingency is prudent from both a system reliability and cost standpoint (the installed price of a new 138 kV transformer based on the recent install at the Sunnyside terminal station would be $2.8 million, plus or minus 20%). Nonetheless, considering the events of January 4, 2014 when two transformers were forced out of service at Sunnyside and Western Avalon respectively; the age and condition of Hydro's transformer fleet; and the potential impact of future load growth on and around the Avalon Peninsula in particular, Hydro agrees with Liberty's recommendation 4.5 that a cost/benefit analysis of the option of securing a spare transformer be completed. Hydro will complete the recommended study in 2015.

Hydro acknowledges and agrees that Liberty's conclusion 4.22 is an accurate reflection of Hydro's deployment of transformers in distribution substations, and the fact that only some feeders can be tied to other feeders in the event of an outage. As Liberty note, this is typical of rural distribution systems.

5.4 Protection and Control

Table 5.4 below identifies Liberty's conclusions related to protection and control.

Hydro acknowledges and agrees with Liberty's conclusions related to Hydro's protection and control (P&C) standards and practices.

In their conclusion 4.31, Liberty refer to the P&C action items in Hydro's 2014 IAP, which Hydro notes required a significant allocation of time and resources during the year, but which were substantially competed as planned in 2014. In addition to the specific actions planned in the IAP, P&C resources were also required in support of various capital and maintenance projects carried out in 2014, including those that were incremental to Hydro's original 2014 workplan (e.g., planned outage support). The carry-over of P&C related IAP actions into 2015 was minimal in relative terms, and all but two have since been completed. The remaining actions are scheduled for completion in February.

TABLE 5.4 **LIBERTY'S CONCLUSIONS ON PROTECTION & CONTROL**
Protection and Control staffing is appropriate (4.25).
Protective relay scheme designs conform to good utility practice (4.26).
Relay testing cycles conform to good utility practice and backlogs are reasonable (4.27).
Hydro uses an industry standard software package for conducting short circuit currents and relay coordination studies (4.28).
Protection and Controls personnel have appropriate involvement with investigations of relay scheme malfunctions (4.29).
Hydro has resumed replacement of obsolete electromechanical relays (4.30).
Hydro has reported progress in completing the 2014 Integrated Action Plan items involving protection and control; however, some have been delayed, as noted earlier in this chapter (4.31).

6 TRO ASSET MANAGEMENT

Table 6.1 below identifies Liberty's conclusions and recommendations related to asset management in Transmission and Rural Operations (TRO).

Hydro acknowledges and agrees with Liberty's conclusions 5.1, 5.2, 5.3, 5.5, 5.7, 5.8, 5.9, and 5.10. Further discussion follows on certain aspects of Liberty's conclusions and recommendations.

6.1 Investments in Maintenance and Asset Renewal

As Liberty note in their conclusion 5.9, Hydro has made significant investments in the renewal or replacement of its transmission and distribution infrastructure. Hydro's Internal Review Report of March, 2014 noted that many of Hydro's key generating and transmission assets were installed in the late 1960s and the 1970s. Transmission assets are aging, with over 50% of Hydro's transmission lines in service for more than 35 years. Over the last five years, formal condition assessments have been completed on many key assets and asset groups, and resulting recommendations have been integrated into 20, five and one year asset management plans and related capital plans. This planning was a key factor in the more than two-fold growth in Hydro's capital expenditures between 2005 and 2013. Capital investment in transmission and distribution specifically is expected to increase from approximately $35 million in 2013 to approximately $73 million in 2017 and then $62 million in 2018.

In the meantime, Hydro recognizes that an aging asset base also requires increasing attention from a maintenance standpoint. This is reflected in Hydro's budget allocations for operations and maintenance, which aim to ensure adequate resourcing for the work to be done. Hydro has also focused more attention on its processes for work planning and execution to ensure that maintenance work is planned and completed in an efficient and timely manner. Significant progress was made in this area in 2014, and Hydro is confident that changes it has made will improve the efficient execution of maintenance work within TRO operations.

TABLE 6.1
LIBERTY'S CONCLUSIONS & RECOMMENDATIONS – TRO ASSET MANAGEMENT

CONCLUSIONS	RECOMMENDATIONS	
The advanced age of much of Hydro's T&D equipment will require substantial levels of maintenance and replacement (5.1). Hydro conducts vegetation management consistent with good utility practice and the needs of the system (5.2).		
Recent improvement in air blast circuit breaker maintenance has produced conformity with good utility practices (5.3). It is not clear that Hydro brings to bear sufficient numbers of skilled resources to prevent undue backlogs in maintenance work (5.4). The radial configuration of the distribution and portions of the transmission (particularly 66 kV) systems leads Hydro to defer maintenance work to avoid required customer outages (5.5).	5.1	Formulate a comprehensive and structured plan to bring maintenance backlogs to a more appropriate sustained level.
Hydro does not make available to its field personnel the electronic equipment that has come into common use in the industry (5.6).	5.2	Perform a cost/benefit analysis of providing crews with laptop computers.
Hydro's annual Wood Pole Line Management program reflects best utility practices (5.7). Hydro has been appropriately funding its operations and maintenance work (5.8). Hydro has been increasing its transmission and distribution capital investments (5.9). As of the December 10, 2014 report, Hydro reported itself to be on track for completing the transmission and distribution actions listed in the Integrated Action Plan (5.10).		

6.2 Maintenance Backlogs

Hydro has worked diligently throughout 2014 to reduce its maintenance backlogs[15] and as noted in response to PUB-NLH-378 and 379 Hydro increased its deployment of temporary and contractor resources in 2014, and this increase in resources will continue in 2015 as required to maintain a stable level of work in the backlog which ensures that critical work is completed, and recognizes the reality of increasing maintenance activities resulting from aging equipment and its components.

Liberty's conclusion 5.4 regarding the sufficient use of resources to prevent undue backlogs in maintenance work is not definitive but rather is directional in nature. In order to obtain greater clarity on this issue Liberty's recommendation 5.1 calls for Hydro to complete a comprehensive and structured plan to bring maintenance backlogs to a more appropriate, sustained level. Hydro accepts this recommendation and the necessary activities to complete this plan will be incorporated into its 2015 workplan.

6.3 Maintenance on Distribution Assets

As Liberty's Report notes, when Hydro defers maintenance on radial distribution lines, it does so only in situations where the work involved would result in extended customer interruptions, and only after an analysis of failure risk in the absence of maintenance has been completed. Balancing maintenance execution against customer service impacts and safety considerations is more of an operational challenge in radial distribution areas, and there are some occasions when longer outages to accommodate maintenance or capital work are unavoidable.

As noted earlier, Hydro plans to investigate other methods that may be available to reduce T-SAIDI. In that process, Hydro will also assess options that may specifically apply to

[15] The term "backlog" as utilized by Hydro's scheduling system was fully described in Hydro's responses to PUB-NLH-378 and 379.

distribution, as well as the extent to which options that are identified for transmission equipment may apply to distribution facilities.

6.4 Using Mobile Technology in the Field

Hydro acknowledges Liberty's conclusion 5.6 and agrees that it uses mobile devices such as laptops in the field in a limited manner at the present time, primarily by Technologists. Hydro did complete a pilot test of the use of tablets by field crews for work method purposes in 2014. These devices did not provide any meaningful value, and these learnings will be considered in Hydro's future consideration of other options.

One factor affecting the adoption of a consistent mobile technology strategy for field operations has been the unavailability of reliable network/internet connectivity in the more isolated areas of Hydro's geographic territory. There are areas throughout both the island of Newfoundland and in Labrador, which overlap significantly with Hydro's territories, which do not have reliable network coverage. However, there may be satellite-based alternatives to address this. As well, the adoption of laptops in field operations as a "passive" work tool may be justified on a cost/benefit basis (i.e., to enable the paperless documentation of work orders or the recording of data for later storage). Hydro agrees with Liberty's recommendation 5.2 and Hydro's intention is to build on the work already done and complete an analysis of mobile technology options and costs in 2015.

7 SYSTEM OPERATIONS

Table 7.1 below identifies Liberty's conclusions related to Hydro's system operations.

Table 7.1 **Liberty's Conclusions Related to System Operations**
Hydro's Energy Control Center has an adequate number of experienced operators and trainees, as well as well-defined roles for support engineers (6.1).
Hydro's Energy Control Center is appropriately equipped with computer-based tools for operating its transmission system, including SCADA monitoring and control, Energy Management System energy and demand management (6.2).
Hydro shares real-time data, via a link between SCADA systems, with Newfoundland Power (6.3).
Hydro has not installed SCADA monitoring and control on a sufficient number of its distribution feeders (6.4) (*see Recommendation 4.6*).

Hydro acknowledges and agrees with Liberty's conclusions 6.1, 6.2, and 6.3.

Hydro has previously indicated its agreement with Liberty's conclusion 4.20 in relation to its limited use of SCADA monitoring in its transmission terminal stations and distribution sub-stations, and it acknowledges Liberty's conclusion 6.4 related to the same topic. Hydro has also indicated its agreement with Liberty's related recommendation 4.6 (see Section 4.2.4).

8 OUTAGE MANAGEMENT

Table 8.1 below identifies Liberty's conclusions and recommendations related to outage management.

TABLE 8.1
LIBERTY'S CONCLUSIONS & RECOMMENDATIONS – OUTAGE MANAGEMENT

CONCLUSIONS	RECOMMENDATIONS	
The manual, paper-based outage management process does not conform with best utility practices (7.1).	7.1	Study the costs and benefits of a variety of Outage Management System opportunities in order to provide a basis for assessing potential options.
The ability to detect customer outages following installation of automated meter reading should work with an Outage Management System (7.2). Hydro has adequate protocols for communication with Newfoundland Power regarding planned transmission, generation, and terminal station equipment outages (7.3).		

Hydro acknowledges and agrees with Liberty conclusions 7.1, 7.2, and 7.3.

On-line outage management systems which serve both electricity providers and their customers are common in today's electricity systems, particularly in utilities whose main customers are residential users. Hydro acknowledges the potential benefits of such systems as generally summarized by Liberty in their Report, but recognizes that this potential will vary from one utility to another based on differences on many variables. These include, but are not limited to, the utility's operational profile (e.g., transmission vs. distribution); customer base; geographic scope; existing on-line feeder monitoring (SCADA) capabilities; internal processes for coordination between corporate communications and operations personnel; and the complexity of the electricity market being served (i.e., the number of wholesale and retail electricity providers).

Hydro agrees with Liberty's recommendation 7.1 and it will complete a cost/benefit analysis of the available outage management system options. This will require significant consultation with Newfoundland Power to ensure that any options under consideration can be appropriately integrated between the two companies for the maximum benefit of electricity customers in the province. Hydro's review of its SCADA systems will also be integrated with this effort to ensure that the benefits of any potential expansion of that system from an outage management perspective are also understood and considered.

9 EMERGENCY MANAGEMENT

Table 9.1 below identifies Liberty's conclusions and recommendations related to emergency management.

TABLE 9.1
LIBERTY'S CONCLUSIONS & RECOMMENDATIONS – EMERGENCY MANAGEMENT

CONCLUSIONS	**RECOMMENDATIONS**	
The Nalcor/Hydro Emergency Operations Center location, contents, and the assigned staffing duties conform to good utility practices (8.1).		
Hydro's Corporate Emergency Response Plan is generally sufficient, but does not give managers guidance in determining whether to classify an outage event as minor, major, or catastrophic (8.2). Hydro's Severe Weather Preparedness Protocol is generally sufficient, but does not fully address certain matters (8.3).	8.1	Include in the Corporate Emergency Response Plan and in the Severe Weather Preparedness Protocol guidelines for determining how to classify a predicted or actual outage event as minor, major, or catastrophic in terms of numbers of customer interruptions or customer interruption hours, as a minor, major, or catastrophic emergency for determining preparedness requirements.
Hydro's Severe Weather Preparedness Protocol is generally sufficient, but does not fully address certain matters (8.3).	8.2	Develop a Restoration Protocol, in addition to the Severe Weather Preparedness Protocol, to address: (a) assessing storm damage, (b) assigning a Storm Level of activity based on the magnitude of equipment damage and customer outages, (c) providing emergency living quarters and meals for crews, when necessary, (d) protecting the public from downed lines, and (e) prioritizing restoration of terminal stations, substations, and feeders.
	8.3	Include references in the Restoration Protocol to the uses of the various restoration-related Operating Instructions which may apply to Severe Weather related restorations.

TABLE 9.1 **LIBERTY'S CONCLUSIONS & RECOMMENDATIONS – EMERGENCY MANAGEMENT**		
CONCLUSIONS	**RECOMMENDATIONS**	
Hydro provides a number of Operating Instructions that address readiness for specific equipment-caused contingencies that may or may not be related to severe weather (8.4). Hydro conducted 2014/2015 winter preparedness exercises, drills, and tests in recognition of lessons-learned from previous winters, and has enhanced and formalized communications with Newfoundland Power (8.5). Hydro completed all of its emergency preparedness, communication, and coordination Integrated Action Plans Items (8.6).		

Hydro acknowledges and agrees with Liberty's conclusions 8.1, 8.2, 8.3, 8.4, 8.5, and 8.6, with recommendations 8.1, 8.2 and 8.3. Further discussion follows below on certain aspects of these conclusions and Liberty's recommendations.

9.1 Corporate Emergency Response Plan (CERP)

Hydro's Corporate Emergency Response Plan (CERP) was initially developed in 2006. It complements and interfaces with local emergency response plans which normally constitute the first level of response in emergency situations. The two main purposes of CERP are: a) to facilitate the provision of corporate support and resources as required in addressing an emergency situation, and b) to ensure the appropriate level of corporate response from a stakeholder communications standpoint. Hydro acknowledges and agrees with Liberty's conclusion 8.1 that its CERP conforms with good utility practice.

The CERP identifies the criteria to be considered in determining the level of corporate emergency response in an emergency situation, which may range from a low level alert to a partial or full mobilization of the CERP team to the Corporate Emergency Operations Centre

(CEOC) in St. John's. All response levels which involve a confirmed emergency in progress include "Loss of Supply" as a criterion which is linked to the anticipated or possible duration of the outage. From a practical standpoint, other aspects of an outage situation are taken into account as well, including the number of customers potentially impacted. However, these additional considerations are not specifically stated, and Hydro therefore agrees that further guidance can be provided to managers by revising the loss of supply descriptions accordingly. Similar revisions to Hydro's Severe Weather Preparedness Protocol would be appropriate for the same reason. On this basis, Hydro agrees with Liberty's conclusion 8.2 and recommendation 8.1.

9.2 System Restoration and Severe Weather Preparedness

Hydro has a significant amount of experience with system restoration in storm damage situations, and has established practices which address each of the elements identified by Liberty in their recommendation 8.2. Hydro's Severe Weather Preparedness Protocol outlines a comprehensive tactical plan for mitigating and minimizing the impacts of storm-related forced outages. However, Hydro acknowledges that its system restoration processes could be more effectively documented and integrated into this Protocol. Hydro therefore agrees with Liberty's conclusion 8.3 and recommendations 8.2 and 8.3 in this regard.

10 CUSTOMER SERVICE AND OUTAGE COMMUNICATIONS

Table 10.1 below identifies Liberty's conclusions and recommendations related to customer service and outage communications.

TABLE 10.1
LIBERTY'S CONCLUSIONS & RECOMMENDATIONS – CUSTOMER SERVICE & OUTAGE COMMUNICATION

CONCLUSIONS	RECOMMENDATIONS	
Hydro has reported significant progress on the outage improvement recommendations, with remaining work on track for completion (9.1).		
Hydro's largest customers are served and supported largely by the System Operations Department, not the Customer Service Department (9.2).	9.1	Hydro should develop a key accounts management program to support and serve large industrial and commercial customers.
Hydro's Customer Satisfaction Surveys have focused on residential and small commercial customers (9.3).	9.2	Hydro should conduct customer research to better understand its largest customers.

Hydro acknowledges and agrees with Liberty's conclusions 9.1, 9.2, and 9.3 and recommendations 9.1 and 9.2. Further discussion follows below on certain aspects of these conclusions and Liberty's recommendations.

10.1 Outage Communication

An extensive amount of work was completed by Hydro in 2014 to improve customer communication and coordination. Several actions were identified by Hydro through its internal investigation into the supply issues and outages in January, 2014. Other actions were in response to recommendations made by Liberty in their Interim Report. Hydro's 2014 IAP included 17 actions related to customer communication and coordination, and all but one were completed by the end of 2014. Several of these actions were specifically related to outage communication and included, for example, the implementation of a formal protocol and set of guidelines for notifying customers, the general public and other stakeholders in relation to possible supply issues and conservation requests. As well, Hydro and Newfoundland Power have been collaborating closely on understanding customer outage-related informational needs and expectations, and in identifying opportunities to more effectively leverage customer contact technologies in outage situations.

10.2 Industrial and Commercial Customers

Hydro routinely conducts research of residential customers, but has not been as formal in its approach with its industrial and larger commercial customers. The existing customer interfaces managed by Hydro's System Operations group provide mechanisms for obtaining feedback from this relatively small group of customers. Nonetheless, these are customers with whom Hydro has direct customer relationships, and Hydro agrees there are opportunities for strengthening its management of these accounts. Hydro agrees with Liberty's conclusions 9.2 and 9.3 and their related recommendations 9.1 and 9.2 in this regard.

11 GOVERNANCE AND STAFFING

Table 11.1 below identifies Liberty's conclusions and recommendations related to governance and staffing.

TABLE 10.1
LIBERTY'S CONCLUSIONS & RECOMMENDATIONS – GOVERNANCE AND STAFFING

RELATED CONCLUSION(S)S	RECOMMENDATION	
After examining the Hydro board of directors in relation to the usual model for holding company structures, Liberty found a number of areas that can be changed to enhance its effectiveness (10.1).	10.1	Make adjustments that will bring the Hydro board of director structure and operations more in line with the prevailing utility/holding company model.
Hydro lacks a needed, single executive under which it can consolidate the principal functions associated with delivering utility service (10.2).	10.2	Restructure the senior-level executive organization to create a consolidating executive within Hydro, and escalate the regulatory affairs function to the level of officer, reporting to the Hydro consolidating executive.
The use of the Project Execution and Technical Services Group to provide common services benefits Hydro and is appropriately managed, but lacks transparency in certain respects (10.3).	10.3	Submit to the Board a comparison of Project Execution and Technical Services work assignments resulting from the work planning process with home base assignments.
Hydro has made strong first steps in establishing and implementing enterprise risk management (10.4). Even given the strength of efforts to date, it remains important to enhance the use of risk management to address Hydro infrastructure and operating risks (10.5).	10.4	Enhance and finalize the draft master enterprise risk document and engage risk management personnel early and with operations personnel in identifying, sizing, and planning for mitigation of operations risks.

11.1 Board Governance and Executive Structure

Matters related to the Board of Directors of Hydro, including the size and composition of the Board and the remuneration of Directors, are governed by the *Hydro Corporation Act* (2007) (the "Act"). Section 6 of the Act requires that Directors are appointed by the Lieutenant-

Governor in Council and are paid salary or other remuneration that is determined by the Lieutenant-Governor in Council. Similarly, under Section 7 of the Act, the appointment of a Chief Executive Officer for Hydro, and the terms and conditions of a person's appointment in that role, are matters that are within the sole authority of the Lieutenant-Governor in Council.

Hydro notes and agrees with Liberty's conclusion on page 143 of their Report that there was no direct link between the composition and structure of Hydro's board of directors and management and the 2014 supply issues and power outages. In that context, Hydro discusses the areas of board governance and executive structure from an overall organizational effectiveness and continuous improvement standpoint, which Hydro believes is the spirit in which Liberty's conclusions and recommendations have been offered.

11.1.1 Hydro's Board of Directors

Liberty's conclusion 10.1 is based on their opinion that Hydro's Board structure and practices would be more consistent with governance best practices with a stronger focus in three areas:

a) appointing Directors according to a more structured view of the optimum skills and experience needed, and in the process appointing two Directors who serve only on the Hydro Board;
b) ensuring a more in-depth engagement of Directors in Hydro's operations; and,
c) ensuring that Board member compensation is commensurate with the expectations related to the time and effort required.

Over recent years the Hydro and Nalcor Boards have instituted several changes which have brought governance practices more in line with recognized best practice. These changes have been implemented as Hydro's parent company, Nalcor Energy, has grown and diversified. With the establishment and evolution of Nalcor, the fairly simple corporate structure of the Hydro group of companies in 2006 has evolved to a point in 2015 where there are 13 separate corporate entities within Nalcor, each with an active Board of

Directors. Recognizing the significant growth that Nalcor will continue to experience with Hydro's interconnection with the North American market and with other business expansion, Nalcor has taken steps to address the remaining elements of its governance strategy, and additional changes will be required.

In relation to b) above, Hydro agrees that an engaged and involved Board of Directors is an important aspect of corporate governance. In 2014, Hydro's Board of Directors met on 11 separate occasions, which included both regularly scheduled meetings and special meetings. In addition, there were 11 meetings of the various Committees of the Nalcor Board (Audit; Governance; Safety, Health and Environment; and Compensation), which share common Directors with the Hydro Board. Hydro believes this level of Board activity is indicative of the Board's active engagement in Hydro's business. However, in view of Liberty's comments, Hydro will engage its Board on this matter in the context of Nalcor's ongoing development of its governance strategy.

11.1.2 Hydro's Executive Organization

11.1.2.1 Consolidating Hydro Executive

With respect to Liberty's conclusion 10.2, Hydro acknowledges that its current executive structure below the level of President and CEO does not consolidate all principal functions associated with the delivery of a utility service under one single executive.

The senior most position responsible for Hydro continues to be the President and CEO, which has been the case for many years. Prior to March, 2013 executive level accountability for Hydro operations below the level of the CEO was in fact unified under one executive, the Vice-President of Regulated Operations. The structure observed by Liberty, under which both the Vice-President of Hydro and the Vice-President of System Operations and Planning each report to the CEO, has been in place since March, 2013. This structure, with two senior level operational executives, was implemented shortly after formal sanction of the Muskrat Falls project in December, 2012, and was intended as a transitional structure that ensured a greater executive level focus on the future integration of Muskrat Falls with existing electricity operations from a technical system operations perspective (Vice-President, System Operations and Planning), while maintaining senior level operational accountability for Hydro's ongoing operations (Vice-President, Hydro).

Hydro's structure will evolve still further as Nalcor finalizes its structure for long-term electricity operations in a post-Muskrat, interconnected North American electricity market. In a steady state operating environment, Hydro would not sustain its current executive structure. However, Hydro's environment is a very dynamic one, and the manner in which Hydro and Nalcor will be structured for longer term electricity operations is under review.

Hydro has taken significant steps to add to its senior management group to provide greater operations support to the Vice-President of Hydro. In early 2014, two new positions were created and put in place: a) a Chief Operating Officer, responsible to the Vice-President of Hydro for generation and transmission operations; and b) a General Manager, Gas Turbines and Diesels, responsible to the Vice-President of Hydro for all aspects of asset management related to GTs and diesels. Further, the matters under review in this process have heightened management's awareness of the key near term activities which will enhance system reliability and Hydro's management is committed to ensuring these activities occur as noted throughout this Reply.

11.1.2.2 Regulatory Affairs

Liberty's recommendation 10.2 also suggests that the regulatory affairs function be elevated to the level of an executive reporting to the consolidating Hydro executive. Hydro acknowledges that the regulatory affairs function in a regulated utility is a critical one, and that it should have the profile and authority that is appropriate in that context. The Hydro Finance group was created inside Hydro in late 2013, and in the process consolidated the Rates and Regulatory group, the Hydro Finance division, and the Supply Chain group under one senior manager reporting to the Vice-President of Finance and CFO on a functional level, and to the Vice-President, Hydro on an operations basis. Additional staff resources were added to the Rates and Regulatory group at that time as well.

Hydro's intention is to fully consider Liberty's recommendation as part of Nalcor's determination of its longer-term structure for electricity operations. This structure, which will be different from Hydro's current organizational setup, will include a structure for regulatory affairs. A consideration in this regard will be whether and how existing regulatory affairs and oversight might be best integrated with Hydro's future regulatory processes related to North American reliability compliance. These and other current unknowns will be addressed in an integrated manner.

11.2 Enterprise Risk Management

Hydro agrees with Liberty's conclusions 10.4 and 10.5 and their recognition of the progress made by Hydro to date in relation to its enterprise risk management framework, and Hydro also acknowledges the importance of ensuring that this framework appropriately enables the management of Hydro infrastructure and operating risks. Hydro also agrees with Liberty's recommendation 10.4 and will ensure that operations personnel are fully engaged in identifying, sizing and planning for the mitigation of operational risks within Hydro's risk register.

11.3 Project Execution and Technical Services

The Project Execution and Technical Services (PETS) division of Nalcor provides common engineering and technical services to Hydro and to other Nalcor business units. As they note in their Report, Liberty sought to determine whether there was any reason for concern that the provision of common services has disadvantaged Hydro in terms of securing access needed to provide the proper installation and operation of facilities required to provide reliable service. Hydro agrees with Liberty's conclusion that the use of the PETS group to provide common services benefits Hydro and is appropriately managed.

Liberty also concluded that Hydro's common services arrangement lacks transparency in certain aspects. Hydro acknowledges that transparency on common services is important for regulators and other stakeholders, and Hydro also agrees, as Liberty note in their report, that stakeholders may not have had an opportunity until the current rate application to fully examine and understand these arrangements. Hydro has replied to several Requests for Information related to shared services as part of its rate application and during the course of the Board's outage inquiry, and is agreeable with supplying the additional information referred to in Liberty's recommendation 10.3. Hydro will provide the requested comparison to the Board by March 1, 2015 as recommended.

12 SUMMARY AND FINAL COMMENTS

Hydro is in substantial agreement with Liberty's additional recommendations in their Phase I Report, particularly those that are focused on equipment availability and reliability and the management and maintenance of aging generation and transmission assets. Hydro has been working diligently to continuously improve its performance in these areas and appreciates Liberty's comments on the substantial progress that has been made to date. Hydro addresses these areas and all others covered by Liberty's Report in some detail in the earlier sections of this Reply.

In this final section, Hydro would like to take the opportunity to briefly summarize its position on the central questions that the Board's investigation and inquiry were intended to address. While other aspects are obviously related to, or have become part of, the scope of the Board's Phase I review, the Board's original order indicated an intention to: a) explain the system events that occurred on the IIS in December, 2013 and January, 2014; b) examine each utility's response to these events; and, c) evaluate possible changes to enhance preparedness for 2014-16.

In their final Phase I Report, Liberty states that it "...continues to conclude, in full accord with Liberty's Interim Report, that the outages of January 2014 stemmed from two differing sets of causes: (a) the insufficiency of generating resources to meet customer demands and (b) issues with the operation of key transmission system equipment." Under these general categories of generation and transmission availability, Liberty identifies related contributing factors which Hydro has sub-categorized as follows:

a) The need for Hydro to prioritize the work required to support unit availability by December 1 of each year;
b) Hydro's asset management and preventative maintenance activities (including the testing of its air blast circuit breakers); and,
c) Other factors contributing to the supply shortage in 2014.

Generation Availability by December 1st Each Year

Liberty state the following on page 4 of their Report:

> "Hydro correctly seeks to make its generation available by December 1 of each year. The goal is to complete required maintenance and repairs by the time that each winter season begins. This goal recognizes the significant probability that Hydro may experience its winter peak loads sometime in December. Hydro did not, however, meet that goal for December 2013. We found that Hydro needs to place a higher priority on finishing the work required to support unit availability by December 1. Sound reserve planning cannot assume such availability if Hydro remains unable to support it."

Hydro fully acknowledges and agrees with the importance of ensuring unit availability by December 1 of each year. This has been and will continue to be of the highest priority for Hydro. It is important to note, however, that unforeseen events which were not within Hydro's control, prevented the December 1 target from being met in 2013.

The reasons why the Hardwoods and Stephenville gas turbines could not be made available for service by December 1, 2013 were outlined in detail in Hydro's response to PUB-NLH-072, and in the follow-up information provided in responses to IC-NLH-008, IC-NLH-009, and PUB-NLH-149. These responses also explain the scope of the actions that Hydro evaluated and undertook in response to the need for unforeseen repairs to these units in the months leading up to the 2013/14 winter period.

As Liberty note at page 26 of their Report, Hydro has been aware of the issues associated with the Hardwoods and Stephenville turbines and has spent a great deal of time and effort (in 2014 and before) to improve their availability. The actions Hydro undertook in 2013 were reasonably and prudently focused on ensuring that these generation assets would be available and in service as soon as possible prior to the expected winter peaks, taking all circumstances into account (including the timing of the planned outage of the Holyrood Thermal Generating Station and Hydro's operating load forecast for December as explained in detail in the above-referenced RFI responses). Hydro will continue to place the highest priority on achieving its December 1 goal for generation availability in future years.

Hydro noted the following in its response to CA-NLH-084:

> "For 2015, Hydro is investigating the balance between resources, cost and reliability in planning all generating assets to be available for Mid-November. This approach allows some leeway for unforeseen schedule changes and forced outages to generating units. This proactive approach will meet the needs of Hydro's customers and should allow time to address unforeseen maintenance prior to December 1."

Asset Management and Preventative Maintenance

Liberty state the following on page 37 of their Report:

> "Hydro's asset management program has been in continuous evolution since about 2006 and has many attributes that are 'best practices,' including:
>
> a) Councils of experts
> b) The stage gate approach
> c) The Execution Work Plan program and work execution managers
> d) A heavy focus on condition assessments of assets and their link to the plan
> e) 1-5-20 year planning
> f) Continuing improvement and evolution, consistent with the guiding framework
>
> Liberty have concluded that Hydro has an appropriate approach to asset management with its program sound in scope and design. However, the program did not reflect appropriately the age and condition of Hydro's assets."

Hydro appreciates Liberty's positive commentary regarding its asset management program. On the point made regarding the age and condition of its assets, Hydro agrees that this needs to continue to be a key focus of the program.

In its response to Liberty's Interim Report on May 2, 2014, Hydro recognized and discussed the implications of an aging asset base. The requirements for asset refurbishment and renewal and increased maintenance were the main reasons that Hydro identified the need for a more aggressive program in these areas in 2006, and started the process to implement an expanded, more formal asset management strategy in 2009. Hydro's investment in asset renewal has substantially increased as well. The majority of the increased investment has been directed towards the renewal of existing assets to ensure that necessary equipment performance and reliability are achieved.

Liberty highlighted specific concerns regarding Hydro's air blast circuit breakers as an example of the need to consider the age and condition of the assets in carrying out preventative maintenance. In this regard, Liberty made the following statements in its Report:

> "Liberty found Hydro's maintenance standards more appropriate for a system comprising equipment of 'younger' vintage than characterizes Hydro's infrastructure. The use of now technologically dated air blast circuit breakers comprises an example. Three such devices failed to operate in the January 2014 events. Hydro did not test these devices prior to the January 2014 events, and only began to do so afterwards." (page 5)

> "Preventative maintenances between 2010 and 2013 for air blast circuit breakers were problematic. Hydro extended the cycles for such maintenance. That extension did not appropriately reflect the needs imposed by the advanced age of the equipment involved. Neither did it respond well to the observed conditions of the air blast breakers." (page 97)

Hydro substantially escalated maintenance of its air blast circuit breakers in 2014, consistent with the recommendations resulting from Hydro's internal review and Liberty's Interim Report. However, it is also important to note that Hydro had identified the testing of its air blast circuit breakers as an issue prior to the January 2014 events, and had commenced substantial work to exercise these breakers in 2013. Following its comprehensive review of the outage incident in Holyrood on January 11, 2013, Hydro implemented the addition of breaker exercising as part of the Company's annual breaker maintenance cycle. Most of

Hydro's breakers were exercised in the period March 1, 2013 to March 31, 2014, including those that experienced problems in January 2014.

In response to PUB-NLH-365, Hydro explained that it deferred some six-year maintenance on air blast circuit breakers in order to ensure that resources were deployed on the most critical work for customer supply. That response noted that the condition of the assets was a consideration and that, if there was a known issue with a given breaker or transformer, it was not deferred.

As noted by Liberty on page 91 of their Report, Hydro diverted resources to work considered most critical for supply reliability (e.g. equipment failures, problems identified by testing and inspections, unexpected growth in resource requirements to perform capital projects). Hydro believes these actions in deferring preventative maintenance to address necessary and un-planned corrective maintenance were reasonable and prudent in the circumstances leading up to the winter of 2013/14.

Other Factors Contributing to the Supply Shortage in 2014

At page 11 of their Report, Liberty cited the following factors as contributing to the supply shortage in 2014:

a) 233 MW of unavailable generation
b) A low load forecast (P50)
c) An LOLH which was higher than that typically used by utilities
d) Relatively low capacity reserves, which were permitted because of the higher LOLH and the forced outage rates that supported that LOLH calculation
e) The decision to delay future new generation in 2012 when forecasted reserves seemed inadequate

Weather has also been identified by Hydro as a significant contributing factor. Liberty state the following on pages 16-17 of their Report:

> "It does not appear that Hydro sought or found the potential 'unusual factors' which are of concern but rather concluded that weather was the cause. *The data supporting this conclusion is reasonable*, but would be more convincing if

> the specific correlations between the multiple forecast exceedances and the weather conditions on those days were provided." (*emphasis added*)

As noted in an earlier section of this Reply, Hydro has agreed to provide further information regarding the impact of weather on the 2013-14 forecast exceedances in response to Liberty's recommendations 2.5 and 2.6. The coincidence of cold weather conditions at the time of generating asset unavailability also contributed to the capacity constraints experienced (as referenced in Hydro's response to NP-NLH-010 in the Island Interconnected System Cost Deferral Application).

Regarding the impact of Hydro's Loss of Load Hours (LOLH) criterion on capacity reserves, Hydro notes that the current LOLH criterion has been in effect in Newfoundland for many years as the most practical choice on the basis of economics (as Liberty indicate on page 19 of their Report). In the context of the isolated nature of the Newfoundland electricity grid and the costs involved in potentially increasing reserves, Hydro's reliance on the modeling approach that had been in use for decades leading up to the winter of 2013/14 was reasonable and prudent in the circumstances.

Hydro has accepted Liberty's recommendations to include the P90 load forecast in its evaluation of power supply adequacy and has proposed a reporting process to regularly monitor reserve margins for future decision-making, as noted above in relation to Liberty's recommendation 2.7. Hydro will continue to constantly assess considerations of reasonable cost versus reliability as part of the overall evaluation of potential actions.

Hydro's decision to delay future new generation in 2012 is another example of the cost considerations that must be taken into account in increasing system capacity reserves. On this issue, Hydro notes the following comments from page 19 of Liberty's Interim Report:

> "...Hydro has forecasted supply deficiencies in the recent past (for example in 2012). Nevertheless, favorable variances between forecasted and actual circumstances enabled Hydro to avoid taking action on them, without suffering adverse consequences. Forecasted new load failed to materialize,

> thus eliminating the previously predicted 2012 deficiency. Not spending money to increase reserves has saved money."

The capacity assistance agreement that Hydro executed with Corner Brook Pulp and Paper ("CBPP") is an example of a cost-effective approach to increase reserve margins in a timely fashion that does not require capital expenditures. As Liberty noted on page 22 of their Report, "Hydro has treated interruptible load as a part of its response to supply needs. The interruptible load secured in early 2014 helped in mitigating the supply shortage that existed".

As Hydro noted in its response to NP-NLH-002 in the Island Interconnected System Cost Deferral Application, the capacity constraints experienced in January-March 2014 were very unusual and not predictable. Although the capacity shortfalls which occurred in and among themselves are not unusual problems to be experienced in the course of a year, the combination of forced outages or forced de-ratings occurring on several generating units at one time is very unusual and, together with the other issues that have been identified, led to the generation capacity shortfalls.

Hydro also indicated in its response to NP-NLH-002 in the Island Interconnected System Cost Deferral Application that it has undertaken a review of the issues with all the generating facilities to determine actions that can be taken in future to reduce the likelihood of the recurrence of the unique combination of events that led to the capacity shortfalls in 2014. As noted in that response, at this point, in hindsight, it is possible to identify mitigation actions. However, based on past experience and the knowledge of the equipment entering into the winter of 2013/14, Hydro could not have reasonably expected to have all the mitigating measures in place to prevent the generation shortfalls that occurred. Hydro's actions in obtaining capacity assistance from CBPP and in operating its diesel and gas turbine plants and Newfoundland Power's gas turbine and diesel plants to continue to serve its customers were reasonable and prudent actions in the circumstances.

Hydro is confident that the recommendations that are being implemented as a result of this overall review process will minimize the possibility that another unexpected and unforeseen combination of events could lead to a similar generation shortfall in the future.

APPENDIX A

Summary of Hydro's Responses to Liberty's
Phase I Recommendations

NL Hydro Response to Liberty Phase I Report Recommendations		
Ref	**Recommendation**	**Hydro's Response**
2.1	Provide the Board with monthly updates on the status of Nostradamus upgrades until the production model is fully in-service and shaken down.	**Agree** See section 3.1.2.2
2.2	By April 30, 2015, provide the Board an assessment of the effectiveness of Nostradamus during the 2014-15 winter and the sufficiency of the model for continued future use.	**Agree** See section 3.1.2.2
2.3	Provide the Board with the guide on system losses under various configurations and any instructions for their use.	**Agree** See section 3.1.2.2
2.4	Continue to include the P90 load forecast prominently in all evaluations of power supply adequacy.	**Agree** See section 3.1.1.2
2.5	By March 1, 2015, provide data relating the actual values of the weather variable on the 2013-14 winter days on which the annual peak forecast was exceeded.	**Agree** See section 3.1.2.2
2.6	By March 1, 2015: (1) clarify Hydro's proposed reconstruction of the winter 2013-14 peak, (2) provide a specific value for the reconstructed peak, and (3) report on the impact of the reconstructed peak on the analysis of 2013-14 forecast exceedances.	**Agree** See section 3.1.2.2
2.7	Validate a reasonable and practical criterion for reserve margins, although not necessarily in the form of a rigid number, and characterize the degree of risk associated with that criterion.	**Agree** See section 3.1.1.2
2.8	Report quarterly on the rolling 12-month performance of its units, including actual forced outage rates and their relation to: (a) past historical rates, and (b) the assumptions used in the LOLH calculations.	**Agree** See section 3.1.1.2
2.9	Report promptly to the Board any potential change in the outlook for the adequacy of supply, including increases in forecasted peaks or reductions in unit availabilities.	**Agree** See section 3.1.1.2

NL HYDRO RESPONSE TO LIBERTY PHASE I REPORT RECOMMENDATIONS		
Ref	**Recommendation**	**Hydro's Response**
2.10	Continue to treat completion of the new CT as soon as possible a high priority for Hydro management, supported by close executive attention.	**Agree** See section 3.2.1.2
2.11	Establish and use a more effective system of reporting and analyzing status to give Hydro management early warning and the opportunity for intervention.	**Agree** See section 3.2.2.2
2.12	In all reports to the Board, provide, and adhere to, a clear definition of reporting practices, including the definition of classifications (such as colors) used to categorize performance status	**Agree** See section 3.2.2.2
2.13a	Prepare an emergency contingency plan to identify all generation resources for a potential supply emergency while the new CT remains unavailable.	**Agree** See section 3.2.2.2
2.13b	Report to the Board all steps being taken to expedite completion of the new CT.	
2.13c	Be prepared to trigger emergency plans when and if extreme weather sufficient to reach or exceed expected peaks is forecast.	
2.13d	Report to the Board daily whenever forecasted reserves for the day are less than 10 percent.	
2.13e	Report to the Board immediately whenever forecast reserves fall under 10 percent during any day.	
2.14	Continue to rely on the old CTs for reliable capacity and continue to focus on steps to improve their availability.	**Agree** See section 3.2.2.2
2.15	Report to the Board by February 15, 2015, the final status of the program for critical spares, its results versus expectations of the master plan, a listing of spares to be procured, and when they will be available.	**Agree** See section 3.2.2.2

NL Hydro Response to Liberty Phase I Report Recommendations		
Ref	**Recommendation**	**Hydro's Response**
2.16	Complete planned demand management analysis on a Hydro/Newfoundland Power jointly scoped, conducted, and developed basis and report to the Board a structured cost/benefit analysis of short term program alternatives by September 15, 2015.	**Agree** See section 3.2.1.2
4.1	Investigate and report on methods that can reduce Planned T-SAIDI.	**Agree** See section 5.2.1
4.2	Analyze and report on the benefits of a dedicated capital program component dedicated to addressing the previous year's 10 to 15 percent worst performing feeders.	**Agree** See section 5.2.3
4.3	When prioritizing reliability projects, include a factor that relates cost to anticipated avoided customer interruption numbers and minutes.	**Agree** See section 5.1.2
4.4	Increase the weighting given to resulting SAIFI, SAIDI, and numbers of customer interruptions and minutes when prioritizing proposed projects.	**Agree** See section 5.1.2
4.5	Perform a structured analysis of the costs and benefits of maintaining a spare for the 125 MVA transformers, considering age and equipment condition and the recent failures of the T1 transformer at Sunnyside Terminal Station and the T5 Transformer at Western Avalon Terminal Station.	**Agree** See section 5.3
4.6	Conduct a structured analysis of expanding the SCADA system to include more and perhaps all distribution substations, in order to reduce customer minutes of interruption, and to reduce SAIDI.	**Agree** See section 5.2.4
4.7	Apply animal guards at distribution substations when conducting maintenance work in the substations.	**Cannot agree at this time, but have agreed to review** See section 5.2.4
5.1	Formulate a comprehensive and structured plan to bring maintenance backlogs to a more appropriate sustained level.	**Agree** See section 6.2

NL Hydro Response to Liberty Phase I Report Recommendations		
Ref	**Recommendation**	**Hydro's Response**
5.2	Perform a cost/benefit analysis of providing crews with laptop computers.	**Agree** See section 6.4
7.1	Study the costs and benefits of a variety of Outage Management System opportunities in order to provide a basis for assessing potential options.	**Agree** See section 8.1
8.1	Include in the Corporate Emergency Response Plan and in the Severe Weather Preparedness Protocol guidelines for determining how to classify a predicted or actual outage event as minor, major, or catastrophic in terms of numbers of customer interruptions or customer interruption hours, as a minor, major, or catastrophic emergency for determining preparedness requirements.	**Agree** See section 9.1
8.2	Develop a Restoration Protocol, in addition to the Severe Weather Preparedness Protocol, to address: (a) assessing storm damage, (b) assigning a Storm Level of activity based on the magnitude of equipment damage and customer outages, (c) providing emergency living quarters and meals for crews, when necessary, (d) protecting the public from downed lines, and (e) prioritizing restoration of terminal stations, substations, and feeders.	**Agree** See section 9.2
8.3	Include references in the Restoration Protocol to the uses of the various restoration-related Operating Instructions which may apply to Severe Weather related restorations.	**Agree** See section 9.2
9.1	Hydro should develop a key accounts management program to support and serve large industrial and commercial customers.	**Agree** See section 10.2
9.2	Hydro should conduct customer research to better understand its largest customers.	**Agree** See section 10.2

NL HYDRO RESPONSE TO LIBERTY PHASE I REPORT RECOMMENDATIONS		
Ref	**Recommendation**	**Hydro's Response**
10.1	Make adjustments that will bring the Hydro board of director structure and operations more in line with the prevailing utility/holding company model.	**Cannot agree at this time** See section 11.1.1
10.2	Restructure the senior-level executive organization to create a consolidating executive within Hydro, and escalate the regulatory affairs function to the level of officer, reporting to the Hydro consolidating executive.	**Cannot agree at this time** See sections 11.1.2.1 and 11.1.2.2
10.3	Submit to the Board a comparison of Project Execution and Technical Services work assignments resulting from the work planning process with home base assignments.	**Agree** See section 11.3
10.4	Enhance and finalize the draft master enterprise risk document and engage risk management personnel early and with operations personnel in identifying, sizing, and planning for mitigation of operations risks.	**Agree** See section 11.2