NEWFOUNDLAND AND LABRADOR HYDRO

Load Forecasting

March 2014

Table of Contents

EXECUTIVE SUMMARY

Newfoundland and Labrador Hydro (Hydro) has completed a comprehensive review of the events surrounding the supply disruptions on the Island Interconnected System during January 2-8, 2014. The review included investigation of the rotating outages that occurred between January 2-8, 2014[1] and the transmission/terminal station equipment failures that occurred on January 4 and 5, 2014. Though some minor improvements are recommended to Hydro's forecasting processes, the review found that forecasting was not a contributing factor to supply disruptions or rolling outages.

This report focuses on the findings of both internal and independent reviews of Hydro's load forecasting processes. The purpose of these reviews was to determine what role the forecasting processes may have played during the January disruptions. Hydro completed its own internal review on its load forecasting methodology. It also engaged Ventyx Inc., a leading supplier of industrial software solutions, to provide independent insight and analyses.

Hydro's long- and medium-term forecasting techniques are accurate and suitable for their intended use. Short-term (seven-day) forecasts vary in accuracy depending on weather and weather forecast accuracy.

While Hydro's forecasting processes were not found to be a contributing factor in the supply disruptions, the reviews did provide some recommendations for improvement. Hydro has accepted these recommendations and will incorporate them during the next medium-term operating forecast cycle in May 2014.

LF1: The load forecasting process should include sensitivity analysis, including sensitivity to extreme weather conditions, particularly in making near term investment decisions. The sensitivity analysis should be used to provide more detailed information on the variability of the forecast to the stakeholders. Newfoundland Power should be asked to provide sensitivity analysis on forecast

[1] Rotating outages occurred on January 2, 3, 5 and 8, 2014.

information it provides to Hydro.

LF2: Hydro's short-term forecasting program does not perform well in unusually low temperatures and improvements are required

LF3: Refinements in the equations for the major end-use on the system, electric heat, should continue and be enhanced through continued surveying of the customer base in terms of both average energy use, and saturation of electric heating.

1 INTRODUCTION

On January 10, 2014, Hydro initiated an internal review of the January supply disruptions on the Island Interconnected[2] System (System[3]). Hydro's view, throughout this process, has been to improve its performance in meeting its mandate to provide least-cost reliable power for Newfoundland and Labrador.

This report focuses on the suitability of Hydro's load forecasts and whether they played any role in the events of the 2014 outages.

On December 14, 2013 Hydro supplied a record-high System demand of 1,501 megawatts (MW) (the Island peak supplied by both Hydro and non-Hydro generation was 1,663 MW). Prior to that date, the System peak was 1,405 MW met in February 2004.

Persistent low temperatures and System operating factors meant demand remained high for the next several weeks. In addition, several major generating plants were unavailable or de-rated. These factors required Hydro to implement its Generation Loading Generation Shortage Protocol (System Operating Instruction T-001) several times.

On January 2, 2014, the System load exceeded the available supply and all steps of the Generation Loading Generation Shortage Protocol were implemented – the last step was to request Newfoundland Power to shed load by rotating feeders, at the same time Hydro shed load by rotating feeders in its service areas.

Further outages occurred as a result of equipment failures on January 4 and 5, 2014.

[2] In this context Interconnected means those parts of the island serviced from the grid (i.e. excluding the isolated communities using diesel power), not interconnection to North America.
[3] 'System' refers to Hydro's system only. System load refers to that met by Hydro, i.e. it does not include load met by Newfoundland Power and Kruger.

2 REVIEW PROCESS

2.1 Internal

During, and immediately following, the supply disruptions in January 2014, Hydro personnel responsible for load forecasting reviewed the forecasts and the forecasting methodology to determine what lessons could be learned for the future.

2.2 Prior Reviews

In recent years, Hydro's load forecasting processes have been analysed as part of several comprehensive reviews of the Muskrat Falls Project.

- In 2011, Navigant Consulting Ltd. completed a document review of Nalcor's decision process studies.
- In 2011, the Public Utilities Board (PUB) commissioned Manitoba Hydro International Ltd. (MHI) to review the Muskrat Falls Generating Station and Labrador-Island Link HVdc projects.
- In 2012, the Government of Newfoundland and Labrador retained MHI to provide an independent assessment of the two generation supply options as prepared by Nalcor Energy.

2.3 Independent Review

Hydro contracted Ventyx, an ABB company and leading supplier of enterprise software and services for asset intensive industries, to perform an independent assessment on Hydro's generation planning and load forecasting processes.

The focus of this work was to provide a review of both the generation planning processes that form the basis of Hydro's strategic plans and forecasts and a review of Hydro's long-term (planning) and medium-term (operating) load forecasting. The work was broken into four main tasks:

- Task 1: Planning and Forecast Process Review - examination of prior independent reviews of Hydro's practices and comparison to standard practices in planning and forecasting.

- Task 2: Generation Planning Criteria - review of the overall planning process and assumptions used by Hydro to develop its current long-range, and strategic forward-looking plans and commentary on the processes and criteria including recommendations for improvements.
- Task 3: Load Forecasting Process - review of the process used by Hydro to develop its long-range load forecast and medium-term operational forecasts, as well as commentary on the processes, including recommendations for improvements.
- Task 4: Strategist Model Review[4] - review of the Strategist Model assumptions used by Hydro to develop its long-range and strategic forward-looking plans and commentary on the processes and criteria including recommendations for improvements. Ventyx reviewed the current database and commented on its appropriateness and how it is being used.

3 BACKGROUND

3.1 Hydro Forecasting Process

Hydro maintains load forecasts with three different time horizons. The forecasts are summarized in Table 1.

[4] Strategist is a computer software system, developed by Ventyx, LLC, which supports electric utility decision analysis and corporate strategic planning. More detail is available in the Ventyx report, included in Appendix A.

Table 1: Comparison of Newfoundland and Labrador Hydro Load Forecasts

	Long-Term Planning Forecast (PLF)	**Medium-Term Operating Load Forecast (OPLF)**	**Short-Term Forecast**
Time Horizon	20 years[5]	5 years	7 days
Time Step	Annual	Monthly	Hourly
Schedule	Q3/Q4	May and December	Five times per day
System	Island Interconnected - Includes NP and Kruger total load generation	Hydro System	Three forecasts: Avalon, System and Island
Primary Purpose	-Reliability Assessment -Planning Resource Developments	-Budgeting -Outage Planning -Hydro-thermal optimization	-Unit Scheduling -Outage Approvals
Responsibility	System Planning	System Planning	System Operations
Primary Source of NP Forecast	Hydro	Newfoundland Power	--
Primary Source of Industrial Forecast	Customers	Customers	--

[5]Extended to 50 years for Muskrat Falls studies

- **Long-Term Planning Forecast (PLF)** - The PLF is the forecast used for assessing the long-term reliability of the Island Interconnected system and for planning resource requirements to meet reliability criteria and typically has a time horizon of 20 years. For long-term requirements, both Newfoundland Power and Hydro Rural Island Systems are simulated by Hydro, while industrial requirements are guided by information directly from the individual industrial customers. The time step for the long-term planning forecast is one year and the forecast is prepared annually. Planning studies for Muskrat Falls have required the forecast to be extended to a 50-

year horizon to cover the full financing period.

- **Medium-Term Operating Load Forecast** (**OPLF)** - The OPLF is used for budgeting and medium-term operational planning, such as outage planning and hydro-thermal optimization and has a time horizon of five years. The time step is monthly and the forecast is prepared one to two times per year, usually in May and November\December. The OPLF includes a forecast of energy and peak demand requirements for Hydro's System with the forecast of requirements being customer driven. All loads (except Hydro's rural load) are supplied by the customers (including Newfoundland Power). Newfoundland Power's peak demand forecast methodology was developed in consultation with Hydro.

- **The System Operations Short-Term Forecast (Short-term Forecast)** - The Short-term Forecast is used for unit scheduling and outage approvals and has a time frame of seven days. The time step is hourly and the forecast is prepared five times a day. Three forecasts are created, one for the Avalon Peninsula, one for the Hydro System, and one for the Interconnected Island System. Newfoundland Power generation is estimated by using the previous day's generation.

3.1.1 Responsibilities

Both the PLF and OPLF are the responsibility of the System Planning group of Hydro's System Operations and Planning Division. The Short-Term Forecast is the responsibility of the System Operations Engineering group, also in the System Operations and Planning Division.

3.1.2 Long-Term Planning Forecasts

There is one PLF cycle completed each year, with the analysis being typically initiated in the last quarter of each year. A primary input to the PLF is the provincial economic forecast which is provided by the provincial Department of Finance. The annual development of long-term load forecasts ensures, to the best extent possible, that the constantly shifting set of parameters affecting electricity demand in the province are incorporated into current utility operating plans and investment intentions. Figure 1 (below) shows a Hydro flow chart of the load forecast cycle, which develops the demand, capital, operating cost, and rate analysis. It gives a prevailing economic forecast for the province.

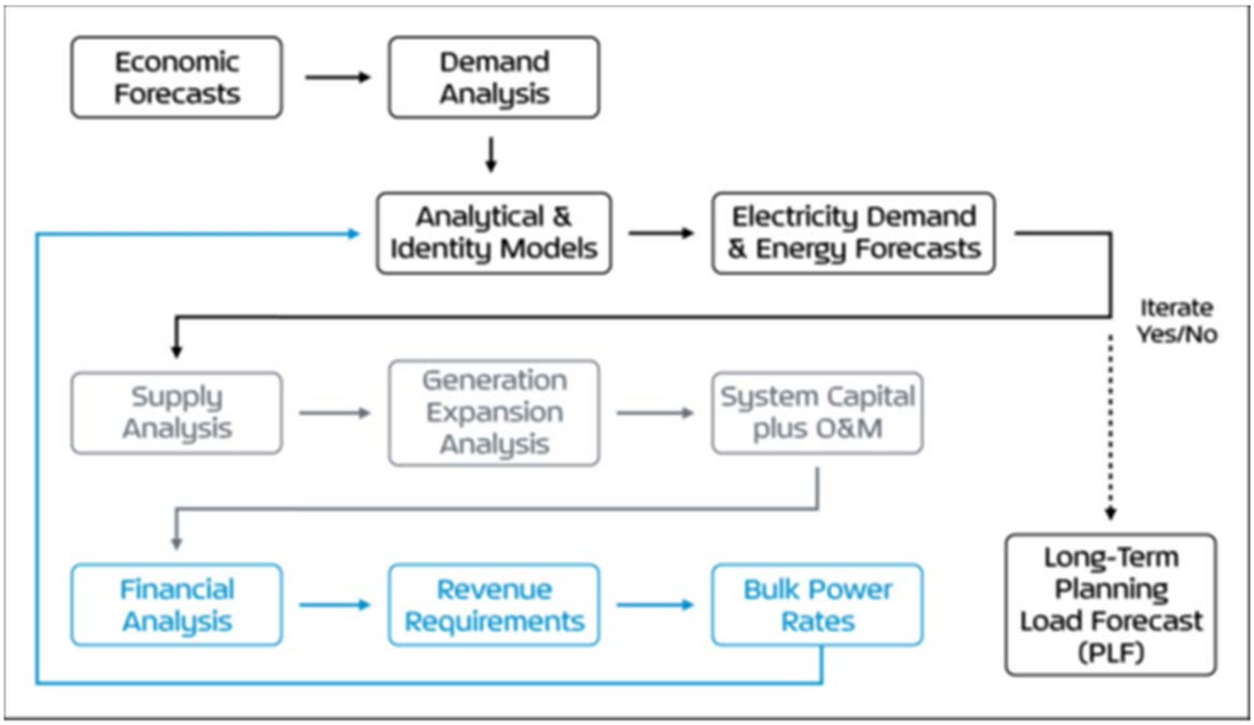

Figure 1: Long-Term Planning Load Forecast Process

The load forecasting model used by Hydro is an econometric model used to project the island's energy and peak demand requirements 20 years into the future. Across the historical period, typically from the late 1960s, the relationships between electricity use and various economic measures are quantified using econometric techniques. The derived relationships can then predict demand levels in future periods, given a certain set of economic conditions. The statistical effort behind the load forecast is primarily directed at long-term forecasting for the utility component of the island's total requirements, i.e., the load forecasts for Newfoundland Power and Hydro's Rural Customers. Data sets and econometric equations, along with all other modeling parameters, are reviewed and updated annually. Once updated, the load forecast model builds up to a forecast of utility load by aggregating forecasts of domestic and general service retail rate classes.

The PLF assumes normalized weather conditions at the time of peak and assumes that any additional load, due to extremes of weather, will be met with System reserve. Based on Hydro's historical record, a weighted island wind chill of -27 C is used as the weather condition for long-term forecasting models. This is the average wind chill which has occurred during historic winter peaks, and is referred to as the normal peak weather condition. While lower wind chills can and will occur, current planning practice relies on system reserve capacity to meet these extreme weather conditions.

Hydro's forecast of total industrial electric power requirements for large Industrial Customers directly served by Hydro is based on direct input from those customers. Given the small Industrial Customer base, Hydro seeks information directly from the customers. Once updated, the load forecast model combines the residential and commercial components of utility load with direct industrial loads, in order to derive the total Island Interconnected load. The total Island Interconnected load is the load Hydro uses for assessing the long-term reliability of the System and planning resource requirements to meet reliability criteria.

3.1.3 Medium-Term Operating Load Forecast

Hydro's OPLF is necessary for the planning and management of the Island Interconnected System. System Operations requires monthly, customer specific, energy and power requirements covering a 39-month reservoir planning horizon.

The OPLF is generally prepared in the May to June time period after Hydro receives forecast demand and energy requirements from Newfoundland Power and Hydro's Industrial Customers. At that time, forecast requirements for Hydro's Rural Customers are typically updated. The aggregation of these monthly power and energy demand forecasts, together with

Hydro's historical based assumptions with respect to customer coincidence and system loss factors, results in a forecast of expected total production for Hydro. An update to the OPLF is often, but not always, prepared in late fall to adjust for Industrial Customers' declared power requirements for the upcoming calendar year.

The most variable aspect of Hydro's load is the Newfoundland Power load. Each spring Hydro requests that Newfoundland Power provide its current five-year load forecast, including annual and monthly energy and peak demand requirements. In the ensuing period, and prior to the receipt of Newfoundland Power's load forecast by Hydro, there is regular communication between Newfoundland Power and Hydro about load forecast related topics, including recent energy and peak demand experience of the Newfoundland Power system, forecast methodology, provincial economic outlook, and weather normalization of energy and peak.

Subsequent to the receipt of Newfoundland Power's five-year forecast and completion of Hydro's long-term planning forecast, which includes Hydro's forecast of Newfoundland Power's energy and peak demand requirements, Hydro and Newfoundland Power will meet to review the overall results. The intent of such discussion is to understand the drivers which results in forecast differences between the two forecast models. This interaction enables both utilities to flag significant forecast differences that might be unexplained by the input drivers, and to make adjustments, if necessary.

3.1.4 Short-Term System Operation Forecasting

Hydro uses a computer program from Ventyx called Nostradamus, for short-term (one-to seven-day) load forecasting. Nostradamus is a neural network, short-term demand forecasting system, which allows users to track forecasts with actual values, as well as update forecasts when new information becomes available. The neural network algorithm learns the pattern of load changes from numerous weather variables, as well as day of week, time of day, and holidays, by learning from historical data. Other input data includes historical load, weather, and generation data.

Guidance from Ventyx suggests that the period of history to use in training the model is between one and five years, ideally since the last major change in load. Generally, Hydro has been using the period from April 2009 for training, the period since the Grand Falls paper mill was shut down. At times, shorter or longer historic periods of data are used to try to improve the forecast.

4 INTERNAL REVIEW

4.1 Operating Load Forecasts

The internal review of the load forecasts focused on why the System experienced several days of peaks in December 2013 and January 2014, which were higher than the winter peak from the Operating Load Forecast for the winter of 2013/14. Several issues were identified, which are considered to be contributing factors to the higher peaks:

- Colder than normal weather conditions in December;
- Higher than expected system demand losses; and
- Higher end-use customer loads, associated with rotating outages in January.

On December 14, 2013 Hydro met record-high System load of 1,501 MW. The operating load forecast's for Hydro's System for the winter of 2013/2014 was 1,478 MW and it was anticipated that the peak would occur in January 2014. The forecast peak for December 2013 was 1,401 MW.

Though the load of 1,501 MW was record breaking, and not forecast for December 2013, it was met without the need for voltage reductions or curtailment because more than sufficient reserve was available. On January 3, 2014 the recorded System peak load was 1,535 MW. The true peak for January 2014 cannot be accurately determined because of the rolling outages that were implemented during the time of the peak and cold load pickup influencing the magnitude of the peaks being recorded.

Historically, the winter peak on Hydro's System usually occurs between December and March. The winter peak is largely dependent on weather conditions and patterns because of the high proportion of homes and businesses with electric heat. Typically, Newfoundland experiences its coldest weather in January and February.

Temperatures in mid- and late-December 2013 were persistently lower than average, and below 0 C. The low temperatures coincided with high wind speeds, which resulted in low wind chill temperatures. Weather conditions on the Northeast Avalon on December 14, as measured by wind chill, were -20 C, in line with historically recorded weather conditions which resulted in winter peaks occurring in December 2013. These cold weather conditions persisted for multiple days. It has generally been observed that the longer a cold spell, the higher the System load, as customers gradually use more electric heat to maintain comfort levels in their homes and businesses. December peak demands are also positively influenced by end-use loads typically associated with the Christmas season. On average, given similar weather conditions, load over the Christmas period is approximately 30 MW higher than it would be later in the winter.

Figure 2 shows the historic variation of Heating Degree Days[5] in December. December 2013 recorded the second highest degree days in this period, and confirms that the weather was persistently cold and would have positively influenced customers' heating/energy requirements.

[5] **Heating Degree Day** (**HDD**) is a measurement designed to reflect the demand for energy needed to heat a building. It is derived from measurements of outside air temperature. The heating requirements for a home or building at a specific location are considered to be directly proportional to the number of HDD at that location.

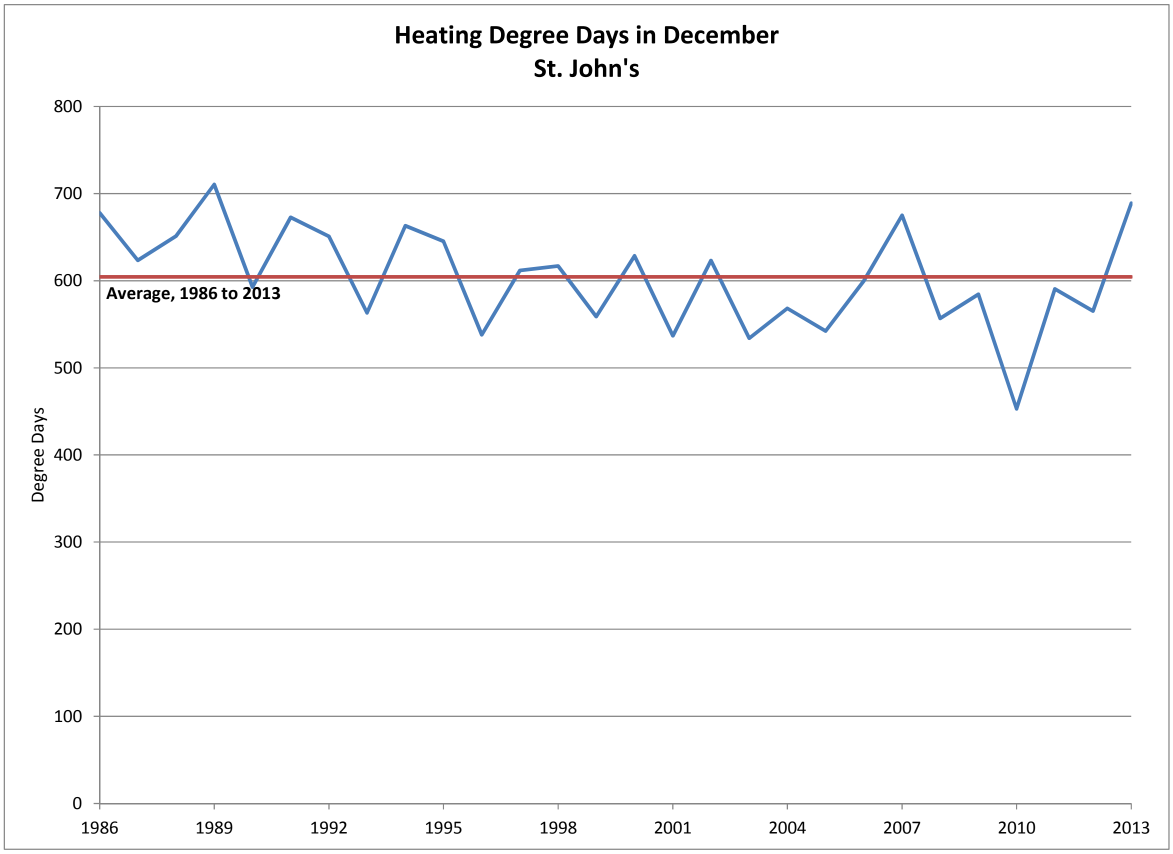

Figure 2: Heating Degree Days in December, St. John's

The Operating Load Forecast is 'weather normalized.' The method used for forecasting winter peak results in a forecast, which reflects average weather conditions (measured as wind chill) coinciding with historical peaks. Historical peaks do not necessarily reflect past weather extremes; meaning, at times of extreme low temperatures, the load could exceed the forecast and system reserve would be used to meet the additional demand (as occurred on December 14, 2013). At times of abnormally mild weather conditions the load would be lower than forecast.

In December 2013 and January 2014 equipment problems meant that, at times, there were several thermal plants that were unavailable or de-rated. The unavailability of the Hardwoods gas turbine and the later supply limitations associated with Holyrood resulted in an increase in power supply to the Avalon Peninsula from Bay d'Espoir through Hydro's transmission system.

This higher load on the transmission lines resulted in increased demand losses on Hydro's System. Demand losses are the electrical losses on the transmission lines and transformers, which are measured as the differences between generation and customer load. Hydro subsequently conducted a load-flow analysis of the conditions experienced in December 2013 and January 2014 and determined the losses to have been 30 to 40 MW higher (approximately double) than what they would have been had all generation been available. The load forecast allowance for losses assumes that the thermal plants are operable in synchronous condenser mode even if they are not on line for generation, which would keep losses at expected values.

In early January 2014 when rotating outages were required because of equipment unavailability, the demands were further increased by the additional demand requirements associated with cold-load pickup on distribution feeders. When customers were returned to service following their rotating outages, they used more energy than they would have in normal circumstances, because of the period of outage. This cold-load pickup requirement was exceptional as broad-based, cold-load pickup is not part of normal day-to-day operations.

An understanding of past forecasting accuracy is important in evaluating the peak in December 2013 and the shortages of January 2014. Table 2 shows the forecast and actual peaks for the winter months from 2004 through 2014. In eight of the 11 years, the forecast was overestimated by between two and nine percent. In three of the 11 years, the actual value was greater than the forecast value, but in two of those years the error was negligible (less than one half percent). Only in 2013/2014 was the discrepancy significantly negative. In the four years prior to this one, the winter peak was overestimated by between two and eight percent. With no marked change in environmental/economic conditions or in forecasting methodology, it could not be predicted that the forecast would be exceeded in 2013/14.

Table 2: Hydro System Peak Demand (MW)

Year	Forecast Winter Peak	Actual Winter Peak	Error
03/04	1399	1405	0%
04/05	1429	1402	2%
05/06	1385	1276	9%
06/07	1358	1323	3%
07/08	1367	1289	6%
08/09	1388	1390	0%
09/10	1372	1305	5%
10/11	1401	1292	8%
11/12	1433	1399	2%
12/13	1461	1378	6%
13/14	1478	1501	-2%

The main finding of this review is that forecasting was not a contributing factor to the supply disruptions and rolling outages in January 2014. One suggestion for improvement is that the load-forecasting process should include sensitivity analysis, including sensitivity to extreme weather conditions, and that analysis should be used to provide more detailed information on the variability of the forecast to the stakeholders. Newfoundland Power should be asked to provide sensitivity analysis on the forecast information they provide to Hydro.

4.2 Short-Term Forecasts

Temperature is by far the most significant variable in short-term load forecasting. The relationship between temperature and peak is demonstrated in Figure 3. In Hydro's opinion, the non-typical, low-temperature conditions, with exacerbating wind chills prevented Hydro's Nostradamus model from accurately forecasting the peak loads in December 2013 and January 2014.

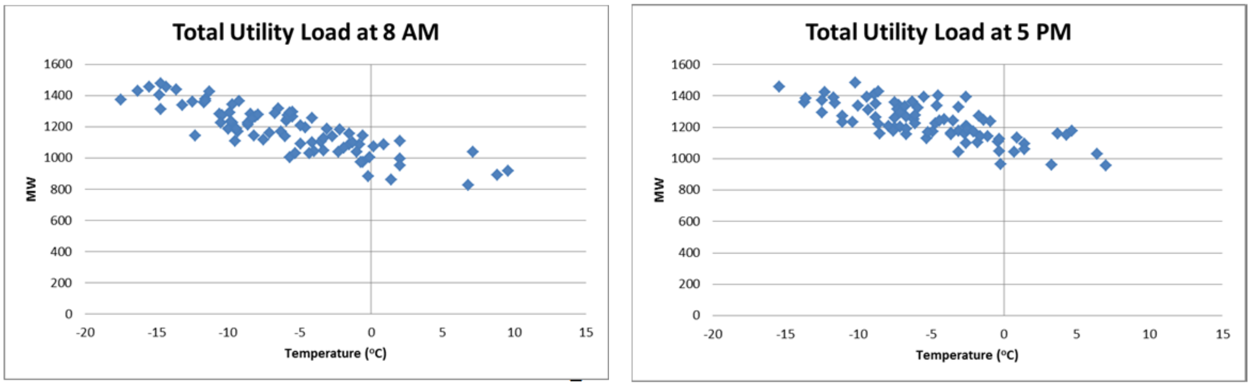

Figure 3: Relationship between Utility Load and Temperature

While the Nostradamus forecast is generally fairly reliable, it has been observed that during periods of unusually cold temperatures and high winds the load forecasts are not accurate. During these times, System Operations staff adjusts the forecasts based on experience and judgment.

A review of hourly temperatures at Badger from 2010 through 2013 showed that less than 0.5% of hourly temperatures were at or below -25 C. Only 2.8% were at or below -15 C. Nostradamus, therefore, had very little data upon which to forecast load at temperatures in the -20 C to -30 C range. Furthermore, most of the historic occurrences of the lowest temperatures were during the night when loads would have been lower than during peak times. The analysis shown in Figure 4 demonstrates that the data used to create the Nostradamus forecast shows almost no correlation between load and temperature at temperatures below -15 C. This is not to say that there is no correlation, or that Hydro does not take it into account in planning, just that the limited data input to Nostradamus does not reflect it.

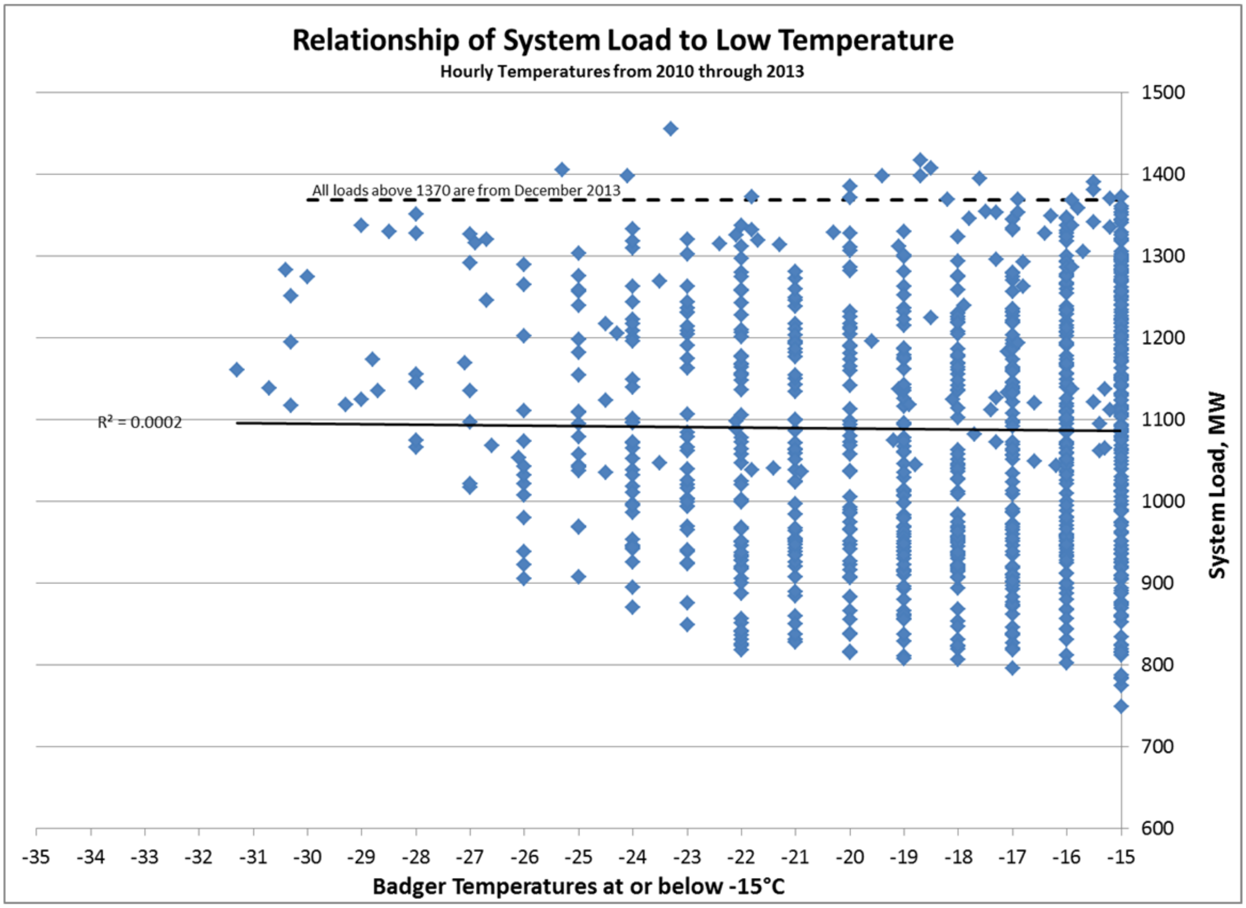

Figure 4: Relationship of System Load to Low Temperatures

System Operations is evaluating an upgrade to the version of the Nostradamus software that it uses for load forecasting, but there have been ongoing difficulties, especially with intraday forecasts. If these issues cannot be resolved with the existing software, new software should be considered.

A more accurate seven-day forecast would not have prevented the supply disruptions in January 2014 as there would not be time within a seven-day period to consider the implications of a higher than anticipated short-term forecast and to add capacity on the System. More reliable forecasts, however, may have been beneficial in managing the rolling outages by giving operators more accurate and advanced knowledge of the expected peaks.

5 VENTYX REVIEW

Hydro retained the services of Ventyx to provide an independent analysis of both the generation planning processes that form the basis of Hydro's strategic plans and forecast, and Hydro's long-term and short-term load forecasting. The results of the Ventyx review regarding Hydro's load forecast is included as Appendix 1 of this report. Ventyx's review of the generation planning process is summarized in the report "Generation Reserve Planning". Specifically, with respect to the load forecast, Ventyx was asked to:

- Review the process used by Hydro in developing its current long-range load forecast and medium-term operational forecasts; and
- Provide commentary on the load-forecasting processes and make recommendations as to specific improvements as required.

5.1 Review Findings

Ventyx's review of the load forecasting process included an examination of Nalcor Energy's documentation relating to the Muskrat Falls project, including the filings with the PUB and the various external reviews, review of the responses to the PUB questions concerning the events of 2014, and one-on-one interviews with both Hydro and Newfoundland Power forecasting staff. Since the independent review of the load forecast conducted by MHI performed a detailed review of the assumptions, Ventyx concentrated its review on the methodology and an assessment of the validity and accuracy of the forecast. Ventyx made no attempt to verify or validate the actual data used since MHI had previously completed the work.

Ventyx reviewed the overall load forecast used in the resource planning process, including Hydro's methodologies for forecasting domestic, general service, street and area lighting classes, and industrial classes. The forecasts for Newfoundland Power and Hydro's Rural Customers are a combination of econometric and regression analyses to determine the energy and demand for each group. The energy by sector is developed using econometric analyses in which the assumptions vary, depending on the various customer classes.

Ventyx concluded that the forecasting methodology used by Hydro is consistent with accepted utility practices. Although the previous review by MHI suggested that the forecasting could be improved by changing to an end-use forecast, it is Ventyx's opinion, based on experience, that the complexity and time needed to generate an end-use forecast would not significantly improve the demand forecast in the mid-term. This is also true since the existing methodology aligns with survey results of the major end-use on the system which is electric space heating.

Ventyx considers that the econometric methods being used are prudent and well validated. The equations all have high statistical coefficients of determination (R^2). The R^2 can be interpreted as the percent of variation in the predicted value that is explained by the given variables. Table 3 enumerates the R^2 for each of the equations. The closer an R^2 value is to 100% the better the fit of the equation to the data provided.

Table 3: Coefficients of Determination

Equation	R^2
NP Domestic Class	
Customer Additions	93.4%
Penetration of Electric Heat	88.5%
Conversion of Non-Electric Heat	78.9%
NP General Services Class	
Electric Heat Customer Load	99.9%
Hydro Rural Domestic Class	
Average Use	98.1%
Hydro General Services Class	
Energy	99.6%
NP Peak	99.7%

Ventyx concluded that the analysis should include an evaluation of the impacts that extreme weather conditions would have on the forecast. These extremes should be evaluated using sensitivities and scenario planning techniques.

Figure 5 shows Ventyx's comparison of the forecasted winter months peaks to the actual peaks for the Hydro System for the years 2004 to December 2013. Since 2004, the forecasted winter peak has consistently been above the actual peaks with the exception of three years. There have been a total of seven months out of 40 winter months that the actual was higher than the forecast. However, since those seven times do not occur in the same month it is likely weather impacting the actual. If a variable, such as the number for customers was off target, it would be impacting the forecast for all winter months in that period.

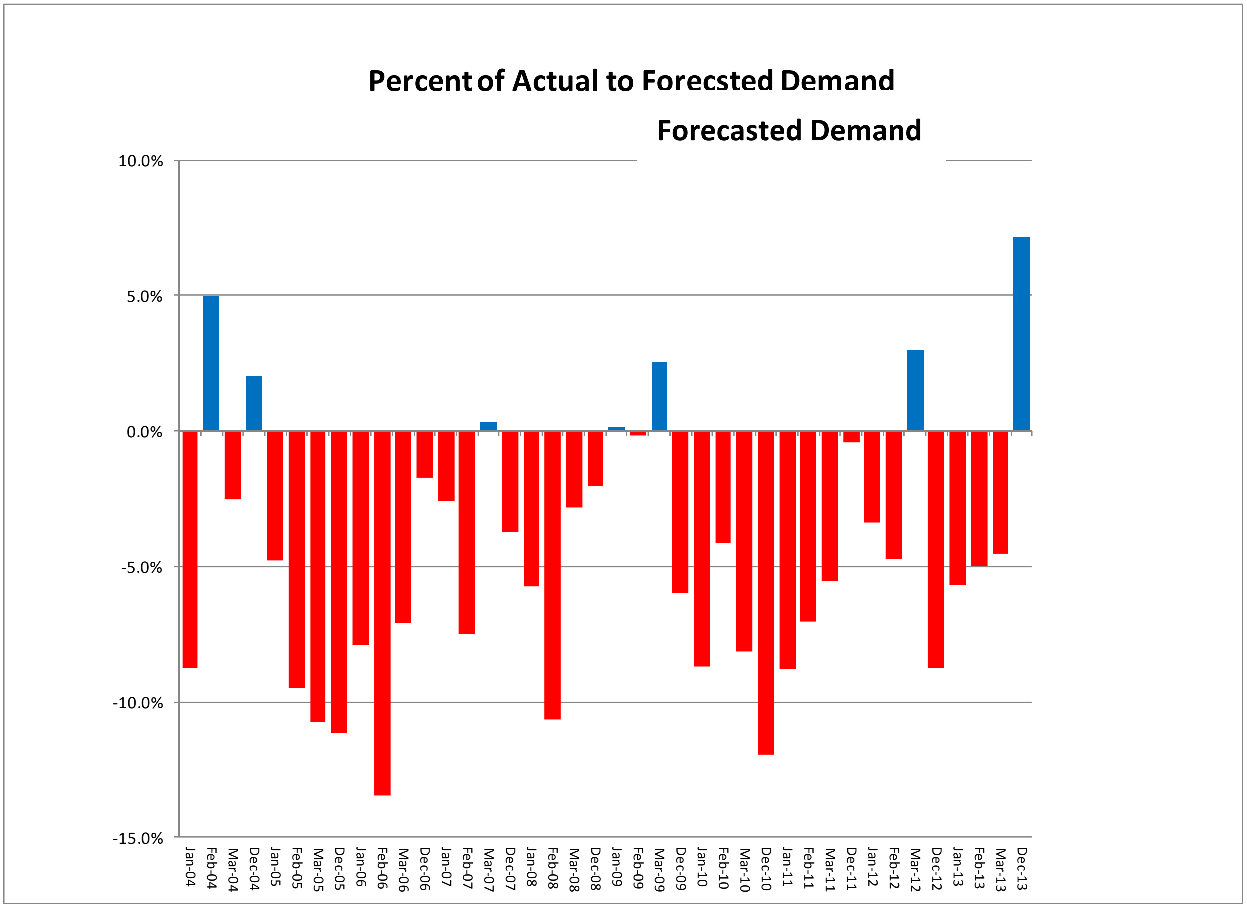

Figure 5: Comparison of Actual and Forecasted Demand

5.2 Recommendations

Ventyx does not consider it necessary to change the forecast methodology to an end-use model because of the increased complexity and cost. The forecast methodology already accounts for the influence of the major end-use on the system: electric heat. Since the R^2 for the two equations involving heating penetrations were 79% and 89%, it would be advisable to continue to refine the models with respect to these variables. This can be further enhanced through continued surveying of the customer base in terms of both average use and saturations of electric heat.

Ventyx recommends that Hydro begin to use formal risk assessment in its planning processes. Alternative load forecasts under extreme weather conditions would be required in both the scenario development and the sensitivity analysis phases.

6 KEY FINDINGS AND RECOMMENDATIONS

6.1 Internal Review

Hydro's internal review of the system disruptions identified several underlying causes of the high System peaks in December 2013 and January 2014: weather conditions, increased line losses, and cold-load pickup demand.

It was determined that forecasting was not a contributing factor to the supply disruptions and rolling outages in January 2014. The review recommends that Hydro's load forecasting processes include sensitivity analysis including sensitivity to extreme weather conditions. The sensitivity analysis could be used to provide more information to the stakeholders on the potential variability of the forecast.

The model that System Operations uses for short-term load forecasting did not perform well during the December 2013 and January 2014 cold temperatures. Hydro is continuing to test a new version of the software and if that does not resolve the issue, it will investigate alternate models.

6.2 Prior Reviews

In 2011 Navigant Consulting Ltd. undertook a review of Hydro's load forecasting methodology and concluded that; "Nalcor's forecast methodology is consistent with generally accepted utility practice and the base forecast for demand and energy growth is reasonable."

MHI's (January 2012) review of Hydro's load forecasting concluded the domestic forecast methodology is acceptable, but that best utility practice would incorporate end-use modelling techniques rather than relying solely on econometric techniques. With respect to the general service sector forecast, MHI concluded that the Hydro model had produced remarkably good results and that end-use forecasting was not recommended because the current models are performing very well.

MHI (October 2012) concluded that the load forecast for the Interconnected Island option is well-founded and appropriate as an input into the Muskrat Falls decision process.

6.3 Ventyx Review

Ventyx does not consider it necessary to use end-use modelling for Hydro's forecasting, however, refinements in the equations for the major end-use on the system, electric heat, through continued surveying of the customer base – in terms of both average use and saturations – may be warranted.

Ventyx recommends that Hydro begin to use formal risk assessment in its planning processes. Alternative load forecasts would be required in both the scenario development and the sensitivity analysis phases.

6.4 Recommendations

Recommendation		Status
LF1	The load forecasting process should include sensitivity analysis, including sensitivity to extreme weather conditions, particularly in making near term investment decisions. The sensitivity analysis should be used to provide more detailed information on the variability of the forecast to the stakeholders. Newfoundland Power should be asked to provide sensitivity analysis on forecast information it provides to Hydro.	Will be incorporated into Hydro's next forecasting cycle, May 2014.
LF2	Hydro's short-term forecasting program does not perform well in unusually low temperatures and improvements are required	In Progress
LF3	Refinements in the equations for the major end-use on the system, electric heat, should continue and be enhanced through continued surveying of the customer base in terms of both average energy use, and saturation of electric heating.	2015 or 2016

ACRONYMS

MHI	-	Manitoba Hydro International Ltd
MW	-	Megawatts
OPLF	-	Medium-Term Operating Load Forecast
PLF	-	Long-Term Planning Load Forecast
PUB	-	Board of Commissioners of Public Utilities

Appendices

2014 Newfoundland and Labrador Hydro Planning Process Review

March 21, 2014

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Contents

Executive Summary

Over the weekend of January 3rd, 2014, Newfoundland and Labrador Hydro ("NLH") experienced a series of largely unrelated events that led to four days of rolling blackouts. On January 17th, The Board of Commissioners of Public Utilities ("the Board") initiated a process to gather information from NLH and Newfoundland Power ("NP") with a focus on whether load requirements on the Island Interconnected system can be met in the near term. Specific issues to be addressed include: asset readiness, maintenance practices, load forecasting, planning criteria and assumptions, equipment performance and reliability, emergency preparedness, system response, and restoration efforts.

NLH retained the services of Ventyx, Inc. to provide a review of both the generation planning processes that form the basis of NLH's strategic plans and forecasts, and NLH's long term (20 year) and medium-term (5 year) load forecasting. Ventyx has not found any evidence that either the generation planning process or the load forecasting process have contributed to the events of January.

In the near term, NLH's current resource expansion plan is within the reliability criteria in all calendar years except 2015.

	Loss of Load Hours (Hours)	Reserve Margin (Percent)
2013	0.97	16.32
2014	2.59	12.28
2015	3.98	10.32
2016	2.73	12.21
2017	2.68	11.00

The previous table is based on the assumption that a new 50 MW CT, is in service December of 2015. If that unit does not achieve that commission date or an equivalent resource is not implemented the LOLH would increase to 4.57 in 2015 and 6.02 in 2016.

NLH is currently considering six options[1] for meeting the expected LOLH in 2015. Each of these options offers the possibility to reduce the system LOLH.

1. Retain the 16 MW (10 MW to the system) diesel facility at Holyrood;
2. Review what is needed to make the remaining 4.6 MW of diesel power at Holyrood available to the system by plant modifications to increase equipment ratings to deliver 14.6 MW capacity;
3. Enter into interruptible contracts with large Industrial customers;
4. Seek already built combustion turbines in the 50 to 100 MW range to supply deficit and blackstart;
5. Initiate the supply of a new 60 MW (nominal) combustion turbine for the Holyrood site to supply deficit and blackstart; and
6. Continue and possibly enhance conservation and demand management initiatives, with the focus on demand management.

The new 50 MW (nominal) combustion turbine or other combustion turbine options are key resources for NLH's near term reliability of supply. The current plan has this unit commissioned in December of 2015. Without this unit, NLH would face LOLH reliability indices of 4.57 hours/year in 2015, 6.02 hours/year in 2016, and 5.71 hours/year in 2017, the Labrador Infeed is in service in December of 2017.

Statistically, demand reduction is a slightly better alternative to generation additions due to inherent uncertainty of generation forced outages. In order to reduce the expected 2015 LOLH of 3.98 hours/year to 2.80 hours/year, in addition to the nominal combustion turbine assumed, NLH would need to secure approximately 40 MW of either interruptible contracts with existing

[1] Newfoundland and Labrador Hydro, *PUB-NLH-062* (Newfoundland and Labrador Hydro: Board Response, February 2014)

customers or conservation and demand management initiatives. If that is not practical, then the difference can be made up from the remaining generation capacity options.

Furthermore, NLH uses reasonable estimates for generation forced outage assumptions as compared to Canadian Electricity Association (CEA) five year averages and the five year averages for its own equipment. The assumptions in Strategist are based upon data collected between 2000 and 2004. The generation forced outage assumption for Holyrood and Bay D'Espoir are 9.64%[2] and 0.91%[3], respectively, and they contributed to the forecast 2015 LOLH of 3.98 hours/year. Recent data from NLH operating data, from 2008 to 2012, indicates that the historical performance for Bay D'Espoir has improved to 0.41% and worsened for Holyrood to 10.69%. These figures are relatively consistent with current performance, however if the generation forced outage assumptions were improved for Bay D'Espoir, the 2015 LOLH would drop to 3.69 hours/year. If the generation forced outage assumptions were changed for Holyrood the contribution to the 2015 LOLH would increase to 4.49 hours/year.

The primary drivers are the Holyrood units. Focusing only on Holyrood, if the Holyrood units could achieve an annual forced outage rate of 8.48% or less then the system would achieve a LOLH of 2.8 hours/year. Recognizing the age of these assets, this may not be practical in the short term and continuing the current assumptions is prudent planning, particular for the near term. As well, there is merit in assessing some variation of this expected performance to gauge sensitivity on the LOLH result.

The current projected plan is based upon a normalized weather forecast. Weather normalization is an industry standard process that adjusts actual peak outcomes to what would have happened under normal weather conditions. Beyond the next seven days weather forecasting is complex and not always accurate. Therefore, NLH should look at a severe

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[2] Source: CEA Typical 2000-2004. Table 6.2.2 100-199 MW Classification for Holyrood.

[3] Source: NLH Operating Experience between 2000-2004. Weighted Average based on Bay D'Espoir units & Hinds Lake, Upper Salmon, Cat Arm and Paradise River

weather sensitivity to gauge how the system might respond to greater than expected demand particularly in making near term investment decisions.

Specific process recommendations:

- Load Forecasting
  - Continued surveying of the customer base in terms of both average energy use and saturations of heating.
  - Develop alternative load forecasts in both the scenario development and the sensitivity analysis phases.
- Generation Planning
  - NLH should continue forward with its generation planning reserve criterion.
  - After NLH's interconnections are established in 2017, NLH should revisit both their generation planning reserve criterion and their modeling of external markets.
  - NLH should continue forward with its practice of maintaining a more conservative estimate of EFOR for the units.
  - Compute a break-even EFOR for each class of its generation to determine the point at which a generator's EFOR will result in the system exceeding the LOLH criteria of 2.8 hours/year
- Develop a formal risk analysis process that utilizes scenarios and sensitivities to test the robustness of resource plans.

Study Objective

Over the weekend of January 3rd, 2014, NLH experienced a series of events that led to four days of rolling blackouts. On January 17th, The Board initiated a process to gather information from NLH and NP with a focus on whether load requirement on the Island Interconnected system can be met in the near term. Specific issues to be addressed include: asset readiness, maintenance practices, load forecasting, planning criteria and assumptions, equipment performance and reliability, emergency preparedness, system response, and restoration efforts.

NLH retained the services of Ventyx, Inc. to provide a review of both the generation planning processes that form the basis of NLH's strategic plans and forecast and NLH's long term (20 year) and medium term load (5 year) forecasting. Specifically, Ventyx was asked to review:

- The overall planning process and assumptions used by NLH in developing their current long range and strategic forward looking plans;
- Provide commentary on the existing planning processes and criteria and make recommendations as to specific improvements as required;
- Review of the process and assumptions used by NLH in developing their current long range load forecast and shorter term operational forecasts;
- Provide commentary on the load forecasting processes, criteria and assumptions and make recommendations as to specific improvements as required;
- Review of the Strategist model assumptions used by NLH in developing their current long range and strategic forward looking plans; and
- Provide commentary on the existing planning processes and criteria and make recommendations as to specific improvements as required.

VENTYX

Ventyx brings a dedicated team of expert consultants that combines experience, industry knowledge, market knowledge, and software expertise to support consulting engagements. Ventyx provides professional consulting services to energy companies in the areas of integrated resource planning, market price forecasting, resource evaluation and planning, trading and settlement, and electric transmission economic analysis. Ventyx has worked with NLH both in support of Ventyx's Strategist software and .with analytical modeling to evaluate the economic and system impacts of the Muskrat Falls hydro project as well as the Maritime Link project with Nova Scotia. Ventyx conducted multiple analytical modeling studies of this pair of projects over a three year period that also included analytical modeling covering the provinces of New Brunswick, Prince Edward Island, Nova Scotia and Newfoundland Labrador as well as surrounding market areas in Quebec, New York and New England for the Atlantic Energy Gateway project

Strategist®

Strategist is a computer software system, developed by Ventyx, LLC, which supports electric utility decision analysis and corporate strategic planning. Strategist is available as a demand-side management analysis system, as a least cost resource optimization system, as a comprehensive planning tool for quick evaluation of hundreds of alternatives, as a finance and rates planning system and as selected application modules that complement planning capabilities already in place. Strategist's advantage as an integrated planning system is its strength in all functional areas of utility planning. Strategist allows analysts to address all aspects of an integrated planning study at the depth and accuracy level required for informed decisions. Hourly chronological load patterns are recognized. Production cost simulations are comprehensive, yet fast. The production costing procedure consists of two stages. In the first stage, the operation of hydro generation and sale and purchase transactions are simulated. The pumped storage facilities, economic energy interchange, and direct load control programs are then economically dispatched based on the marginal cost curve of the system. The result of this first stage is the remaining annual or seasonal thermal load duration curve. In the second stage, the expected operation of the thermal generating units within the year is simulated by a probabilistic technique. The results are the production costs and system reliability indices. The PROVIEW (PRV) Module is a resource planning model which determines the least-cost balanced demand and supply plan for a utility system under prescribed sets of constraints and assumptions. PROVIEW incorporates a wide variety of expansion planning parameters including alternative technologies, unit conversions, cogenerators, unit capacity sizes, load management, marketing and conservation programs, fuel costs, reliability limits, emissions trading and environmental compliance options in order to develop a coordinated integrated plan which would be best suited for the utility. The PROVIEW module works in concert with the GAF Module to simulate the operation of a utility system. PROVIEW's optimization logic then determines the cost and reliability effects of adding resources to the system, or modifying the load through demand-side management (DSM) or marketing programs.

Incident Description

Over the weekend of January 3rd, 2014, NLH experienced a series of events that led to four days of rolling blackouts.

Issues within Scope

The Board initiated a process to gather information from NLH and NP with a focus on whether load requirement on the Island Interconnected system can be met in the near term. Specific issues to be addressed include: asset readiness, maintenance practices, load forecasting, planning criteria and assumptions, equipment performance and reliability, emergency preparedness, system response, and restoration efforts. The scope of this report is focused on the load forecasting and planning criteria and assumptions. With the NLH system setting record peaks during this unfortunate event, the question of load forecast accuracy is raised. The primary planning criteria that are related to an event of this nature are planning reserves and generation forced outage rates. Finally, the issue of load forecasting and planning criteria is enveloped in the overall process of sensitivity analysis to address the inherent risk of the NLH portfolio.

Load Forecasting

Load Forecasting is the process of estimating the demand that customers will place on the system. The process for load forecasting is, generally, defined by the time horizon of a specific forecast. Short term forecasts are hourly in nature and cover the time horizon from next hour to seven days to support short term unit commitment and scheduling. Short term forecasts are focused on the most recent historical relationship of weather to load aligned with short term forecasts of weather conditions. As the load forecasting process passes from the short term to longer term, the reliability of forecasted weather drops dramatically. Longer term forecasts are typically represented as annual peaks and energies, with monthly detail, to support budgeting planning. Longer term forecasts rely on the historical relationships of weather to load along with seasonal patterns and economic drivers.

Generation Planning Criteria

The generation planning criteria for planning reserves and generation forced outage rates combine to form a prediction of the expected LOLH reliability index. This reliability index forms the foundation of a minimum reliability threshold of 2.8 hours/year. For each year of the NLH planning horizon, the system is designed to maintain sufficient generation planning reserves to ensure the minimum reliability threshold is met. Generation planning reserves are the MW difference between available capacity and normalized peak demand that are available to meet unforeseen increases in demand, such as extreme load, and unexpected outages of existing capacity. Forecasted trends in LOLH identify whether generation capacity additions are keeping pace with load growth.

Scenario/Sensitivity Planning

Scenario planning is a strategic planning methodology used to identify and assess the inherent risks and benefits of a flexible long term plan. Scenario planning recognizes that many factors may combine in complex ways to create sometimes surprising futures. Scenario planning seeks to identify the causal relationship between factors and demonstrate a plans flexibility to adapt. Scenario planning develops an internally consistent story about the conditions in which the system might be operating in the future that differs from baseline assumptions in sometimes significant ways and usually involves alterations to all of the assumptions at one time. Sensitivity planning varies each of the assumptions either one at a time or in correlated groups to determine how sensitive the results are to changes in the assumptions. These planning techniques are important when there are variables such as weather that can potentially impact the reliability of the system.

Load Forecasting

Background

Load Forecasting is the process of estimating the demand that customers will place on the system. The process for load forecasting is, generally, defined by the time horizon of a specific forecast. Short term forecasts are hourly in nature and cover the time horizon from next hour to seven days to support short term unit commitment and scheduling. Short term forecasts are focused on the most recent historical relationship of weather to load aligned with short term forecasts of weather conditions. The short term forecasts prepared by NLH use a neural network forecasting approach using the Nostradamus modelling software.

A medium term forecast that covers a time horizon of five years is used for budgeting and near-term supply adequacy. The medium term forecasts are a combination of the NP forecast for their service territory and NLH economic and regression processes for their rural customers and customer input for the industrial loads.

Longer term forecasts cover the time horizons of 20 years and are typically represented as annual peaks and energies, with monthly detail, to support long term generation planning. The long term forecast is performed by NLH using economic and regression techniques to forecast NP, NLH rural loads, and Industrial customer forecasts of their loads. The long term forecasts rely on the historical relationships of weather to load along with seasonal patterns and economic drivers.

The review of the load forecasting process included a review of the original filings with the Board concerning the Muskrat Falls Project, review of two independent, detailed reviews of the project, a review of the responses to the Board of questions concerning the incidents this winter, and one-on-one interviews with both NLH and NP forecasting staff. Since the independent review of the load forecast conducted by Manitoba Hydro International ("MHI") was a detailed review of the assumptions, the review described in this report focused on the methodology and a look at the validity and accuracy of the forecast. Personal interviews were held with the staffs of NLH and NP to ascertain the sequencing and procedures of each company and the interfacing and integration of the individual component forecasts into a single product. Of particular interest was the accuracy of the winter peak as it applies to the incidents described above.

- The interviews with the NP load forecasting staff revealed the medium term forecast of NP service territory energy was performed for Domestic, General Services and Area and street light classes. Although the process was different for each class, the basic process is an average use methodology that applied econometric forecasting techniques to determine average use per consumer that was then applied to a customer growth forecast.
- The medium term peak demand for NP was developed using an average load factor methodology that calculates a 15 year average load factor that is then applied to the medium term energy forecast to determine the NP service territory Winter Peak demand. This is a standard utility practice.
- The NLH long term load forecasting process is a combination of econometric and regression analyses to determine the energy and peak demand for NP and the NLH rural

groups with industrial energy and demand requirements conditioned by individual customer input .

- The long term peak for NP is forecast by NLH using regression analyses that link NP peak demand to weather, domestic electric heat customer growth, general service sales growth and other economic factors. The peak for the NLH rural group is calculated using a long term historical load factor method that is applied to the forecasted energy. The industrial peak is developed through direct input of existing industrial customers. No forecast is made of potential new industries unless it is fairly certain that a change is going to be made either through government action or a committed industrial customer.

NLH uses historical hourly shapes to develop typical 168 hourly week shapes for each month of the year. These typical shapes are applied to each year of the study and are adjusted by the Strategist Load Forecast Adjustment ("LFA") module to meet the data entered for peak and energy from the forecast. NLH has not updated the historical data since 2002 and is scheduled to perform the update in the next 12 months as part of the next generation expansion planning exercise. Since the system has had a fairly stable load factor and since the LFA continuously modifies the shape to meet the forecast this should not impact the results of the studies. This would only be a problem if NLH was evaluating new Conservation and Demand Management ("CDM") or time dependent programs such as time-of-day rates.

NLH has elected to set the study period to 50 years so that it would cover the financing period of the Muskrat Falls project. This is typically performed using either Economic Carrying Charge calculations or infinite end-effects with a shorter study period of twenty years. However, after discussion with NLH planning staff Ventyx determined that the manner in which they performed the extension of the load forecast and other model data was consistent with the Strategist end-effects methodology.

Conclusions

The methodology used by both NP and NLH are consistent with accepted utility practices. It has been noted by another independent review, by MHI, that the process could be improved by changing to an end-use forecast. It is Ventyx's opinion, based on experience, the complexity and time to generate an end-use forecast would not significantly improve the demand forecast in the mid-term. This is also true since the existing methodology aligns with survey results of the major end-use on the system which is electric space heating.

The econometric methods being used by NLH are prudent and well validated. The regression equations all have statistical coefficients of determination (R^2) that are in the very high range. The R^2 can be interpreted as the percent of variation in the predicted value that is explained by the given variables. Table 1 enumerates the R^2 for each of the equations. The closer an R^2 value is to 100% the better the fit of the equation to the data provided. The R^2 for the regression equations that directly impact the forecast of system peak demand in the long term are included below.

Equation	**R^2**
NP Domestic Class	
Customer Additions	93.4%
Penetration of Elect. Heating	88.5%
Conversion of Non-Elect Heat	78.9%
NP General Service Class	
Electric Heat Customer Load	99.9%
NLH Rural Domestic Class	
Average Use	98.1%
NLH Rural General Service Class	
Energy	99.6%
NP Peak	99.7%

Table 1 Coefficients of Determination[4]

No attempt was made in this review to verify or validate the actual data used since a previous report was issued by MHI showing a detailed discussion of the data. It is obvious weather has a significant impact on the resulting energy and peak demand forecasts. NLH's forecasting models include weather variables to account for the impacts due to changing weather conditions through the historical period. However, what is missing is an evaluation of the energy and demand impacts due to extreme weather conditions. These extremes should be evaluated using sensitivities and scenario planning techniques.

Figure 1, shows a comparison of the forecasted winter months peaks to the actual peaks for the system for the years 2004 to December 2013. Since 2004 the actual winter peaks have consistently been below the forecasted peaks with the exception of seven months out of forty winter months that the actual has been higher than the forecast. However, since those seven times do not occur in the same month it would suggest that there was some random pattern

[4] Manitoba Hydro International, *MHI-Report-Volume II-Load Forecast* (February 2012)

such as weather that is impacting the actual. A review of the deviations shows that it is largely weather that impacts all the discrepancies As indicated by the red bars, the actuals are consistently less than the forecast because NLH has experienced a period of warmer than normal peak weather conditions over this period. The December 2013 discrepancy was impacted additionally by the “exceptional” loads resulting from unavailable Avalon generation that resulted in higher system demand loads than expected. If a variable such as the number of customers was off it would be impacting the forecast for all winter months in that period.

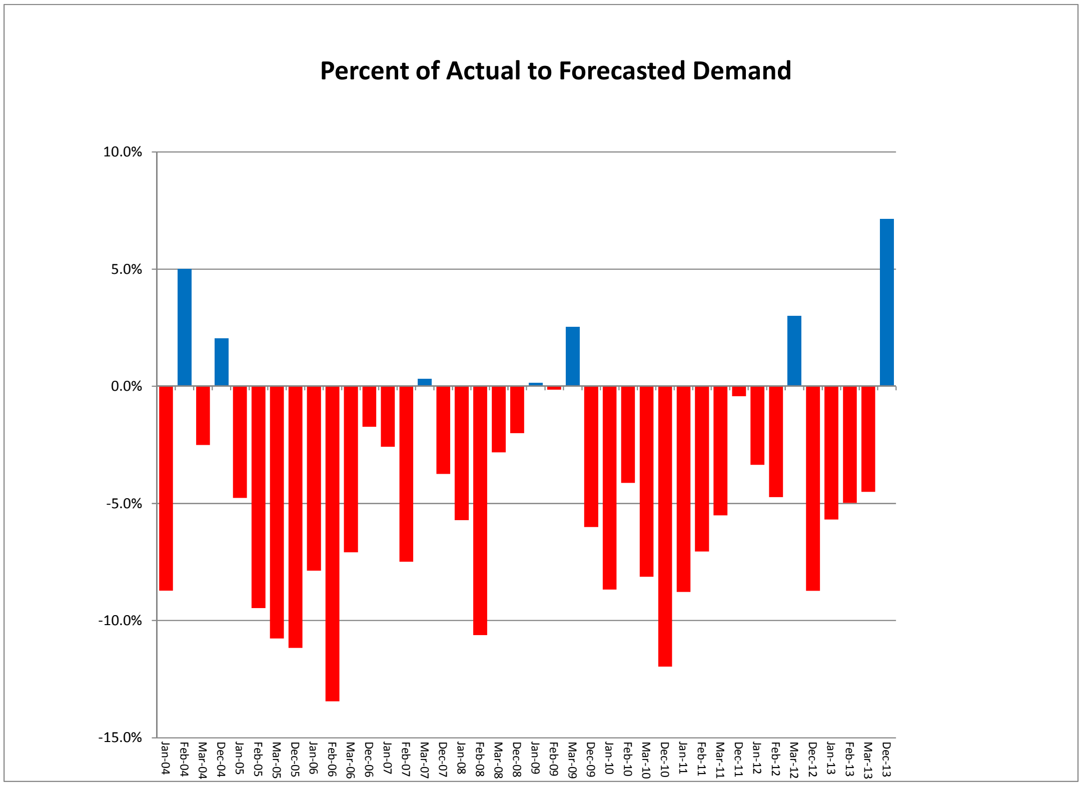

Figure 1[5]

Recommendations

It was noted above that Ventyx does not believe it is desirable to change the forecast methodology to an end-use model. Primarily this is due to the increased complexity and cost, but it is also noted above that the major end-use on the system is electric heat and is already included in the forecast model and thus capturing the majority of any additional detail accuracy

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[5] Newfoundland and Labrador Hydro, *PUB-NLH-011* (Newfoundland and Labrador Hydro: Board Response, February 2014)

benefits that would be expected from an end use model. Since the R^2 for the two regression equations involving heating penetrations were 79% and 89% it would be advisable that NLH continue to refine their models with respect to these two variables. This can be further enhanced through continued surveying of the customer base in terms of both average use and saturation of this end use.

The above discussion has been in terms of the base-case scenario. Later in the report, Ventyx will discuss using a formal risk assessment process that includes the evaluation of plans under extreme weather conditions. As such, it will be important to develop alternative load forecasts in both the scenario development and the sensitivity analysis phases.

Generation Planning Reserve Criterion

Background

The purpose of a Generation Planning Reserve Criterion is to establish the minimum reliability threshold for a power system. The reliability of a power system is defined as the probability of providing customers with continuous service of a satisfactory nature. Reliability is one of the primary factors that drive the planning, design, operation, and maintenance of a power system. The most common index for reliability is the Loss of Load Probability ("LOLP") which is "the probability of the system load exceeding the available generating capacity under the assumption that the peak load of each day lasts all day."[6] Through a series of analytical processes the reliability index, LOLP, is translated to a reserve criterion stated in terms of Loss of Load Hours ("LOLH") or a defined reserve margin percentage. In Strategist, Loss of Load Hours is the expected total number of hours a year during which the utility will not be able to serve all of its customers. The percent reserve margin is based on the reserve margin at the time of the annual peak and defined as the amount of installed reserves, in MW, divided by the

[6] J. Endrenyi, *Reliability Modeling in Electric Power Systems* (Ontario Hydro: John Wiley & Sons, 1978), 4

system peak demand, in MW. This reserve criterion serves as an input to capacity expansion optimization to ensure that all plans selected for comparison meet or exceed the minimum reliability threshold for a power system.

NLH's capacity planning reserve criterion for capacity planning is "The Island Interconnected System should have sufficient generating capacity to satisfy a Loss of Load Hours ("LOLH") expectation target of not more than 2.8 hours per year."[7] The LOLH target is based upon a Loss of Load Probability of 1 day in five years or, more commonly denoted as, 0.2 days per year. In 1977, the NLH System Planning department determined that "The LOLP index to be adopted depends upon the availability of capital. System Planning feels that a .1 days/year is not realistic and would suggest .2 days/year as an optimum value to aim for".[8] The results of NLH's recent 2012 capital planning study, 2012 DCL–PLF IT1–A-0801-_R-105 FE-1 Strategist 4.4.1, are enumerated in Table 2.

	Loss of Load Hours (Hours)	Reserve Margin (Percent)
2013	0.97	16.32
2014	2.59	12.28
2015	3.98	10.32
2016	2.73	12.21
2017	2.68	11.00

Table 2 Expected Loss of Load Hours

[77] PUB-NLH-008

[8] System Planning Department, *Recommended Loss of Load Probability (LOLP) Index for Establishing Generation Reserve Additions* (Newfoundland Labrador Hydro: internal memo, May 16, 1977), 19

Previous table is based on the assumption that a new 50 MW CT, is in service December of 2015. If that unit does not achieve that commission date the LOLH would increase to 4.57 in 2015 and 6.02 in 2016.

NLH is currently considering six options[9] for meeting the expected LOLH in 2015. Each of these options offers the possibility to reduce the system LOLH.

1. Retain the 16 MW (10 MW to the system) diesel facility at Holyrood;
2. Review what is needed to make the remaining 4.6 MW of diesel power at Holyrood available to the system by plant modifications to increase equipment ratings to deliver 14.6 MW capacity;
3. Enter into interruptible contracts with large Industrial customers;
4. Seek already built combustion turbines in the 50 to 100 MW range to supply deficit and blackstart;
5. Initiate the supply of a new 60 MW (nominal) combustion turbine for the Holyrood site to supply deficit and blackstart; and
6. Continue and possibly enhance conservation and demand management initiatives, with the focus on demand management.

The new 60 MW (nominal) combustion turbine or other combustion turbine options are key resources for NLH's near term reliability of supply. The current plan has this unit commissioned in December of 2015. Without this unit, NLH would face LOLH reliability indices of 4.57 hours/year in 2015, 6.02 hours/year in 2016, and 5.71 hours/year in 2017, the Labrador Infeed is in service in December of 2017.

Statistically, demand reduction is a slightly better alternative to generation additions due to inherent uncertainty of generation forced outages. In order to reduce the expected 2015 LOLH of 3.98 hours/year to 2.80 hours/year, NLH would need to secure approximately 40 MW of either interruptible contracts with existing customers or conservation and demand

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[9] Newfoundland and Labrador Hydro, *PUB-NLH-062* (Newfoundland and Labrador Hydro: Board Response, February 2014)

management initiatives. If that is not practical, then the difference can be made up from the remaining generation capacity options.

Furthermore, NLH uses reasonable estimates for generation forced outage assumptions as compared to Canadian Electricity Association (CEA) five year averages and the five year averages for its own equipment. The assumptions in Strategist are based upon data collected between 2000 and 2004. The generation forced outage assumption for Holyrood and Bay D'Espoir are 9.64%[10] and 0.91%[11], respectively, and they contributed to the forecast 2015 LOLH of 3.98 hours/year. Recent data from NLH operating data, from 2008 to 2012, indicates that the historical performance for Bay D'Espoir has improved to 0.41% and worsened for Holyrood to 10.69%. These figures are relatively consistent with current performance, however if the generation forced outage assumptions were improved for Bay D'Espoir, the 2015 LOLH would drop to 3.69 hours/year. If the generation forced outage assumptions were changed for Holyrood the contribution to the 2015 LOLH would increase to 4.49 hours/year.

The primary drivers are the Holyrood units. Focusing only on Holyrood, if the Holyrood units could achieve an annual forced outage rate of 8.48% or less then the system would achieve a LOLH of 2.8 hours/year. Recognizing the age of these assets this may not be practical in the short term and continuing the current assumptions is prudent planning, particular for the near term. As well there is merit in assessing some variation of this expected performance to gauge sensitivity on the LOLH result.

The standard industry practice is to apply a LOLP of 0.1 days/year, or "one day in ten years". However, it should be noted that the 0.1 days/year standard applies to ***interconnected*** utilities. For true "stand alone" utilities, the cost to achieve a 0.1 days/year standard is often cost prohibitive. In 1977, NLH conducted a thorough analysis of system reserves and concluded with the recommendation of 0.2 days/year, or "one day in five years". NLH justified the 0.2

[10] Source: CEA Typical 2000-2004. Table 6.2.2 100-199 MW Classification for Holyrood.

[11] Source: NLH Operating Experience between 2000-2004. Weighted Average based on Bay D'Espoir units & Hinds Lake, Upper Salmon, Cat Arm and Paradise River

days/year over 0.1 days/year based on the economics of meeting the more stringent requirement. The incremental present value revenue requirements necessary to move from a reliability index of 1.0 days/year to 0.2 days/year was approximately $24 Billion[12]. The incremental present value revenue requirements necessary to move from a reliability index of 0.2 days/year to 0.1 days/year was approximately $17 Billion[13]. Simply stated, the cost to serve the last tenth of the reliability index was 71% of the cost to serve the total of the first eight tenths of the reliability index. NLH was justified in its decision to adopt a reliability index of 0.2 days/year.

From a generation mix perspective, the NLH system is "roughly" the same as it was in 1977; there is no reason to reassess its reliability standard of 0.2 days/year. The primary drivers that would prompt a utility to reassess its reliability standard include: resource mix, plant reliability and maintenance, and interconnections. In 1977, the NLH system was 63% hydro and 37% thermal. Today, the NLH system is 67% hydro and 33% thermal. In terms of plant reliability, the capacity weighted average effective forced outage rate in 1977 was 3.74% versus 4.05% today. From a system reliability standpoint, the NLH system is virtually equivalent to the system in 1977. However, NLH expects to complete the Maritime Link to Nova Scotia in 2017. When NLH interconnects with the North American grid, NLH should reassess its reliability standards in light of their access to new markets.

Loss of Load Probability is a characterization of the adequacy of the generation within a system to serve the load of the system. It is important to note that LOLP does not represent the reliability of the bulk transmission or distribution systems. For the purposes of NLH's planning criteria, it was necessary to translate the LOLP, which is a based on the peak load of each of the 365 days, to an hourly equivalent, LOLH. "When Hydro switched from SYPCO generation

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[12] Ibid, Table V. Grand Total (0.2) 2,896,178 (1977 K$) minus Grand Total (1) 2,872,516 (1977 K$) equals 23,662 (1977 K$).

[13] Ibid. Table V. Grand Total (0.2) 2,912,924 (1977 K$) minus Grand Total (1) 2,896,178 (1977 K$) equals 16,746 (1977 K$). 16,746 is 70.07% of 23,622.

planning software to PROSCREEN II [now called Strategist], it was necessary to switch to a Loss of Load Hours (LOLH) criterion. Benchmarking established that a LOLH of 2.8 hours per year was equivalent to a LOLP of 0.2 days per year, for Hydro's system."[14]

In 2017, the Maritime Link to Nova Scotia will be completed. Post 2017, NLH will be interconnected with the rest of the North American grid. In addition, there will be a long term sales agreement with Nova Scotia that will provide scheduling flexibility. NLH's current long term planning system does not reflect the reliability benefits of these incremental additions to the NLH portfolio.

Conclusion

NLH's generation planning reserve criterion of a LOLH of 2.8 hours per year is prudent and consistent with standard industry practices. NLH has consistently used the generation planning reserve criterion as an input to their capacity expansion optimization to ensure that all plans selected for comparison meet or exceed the minimum reliability threshold for a power system.

Recommendation

NLH should continue forward with its generation planning reserve criterion.

After completion of NLH's interconnection with Nova Scotia and Muskrat Falls, NLH should revisit their generation planning reserve criterion of 2.8 hours/year in light of the reliability benefits offered by the access to North American markets. It may be possible that this approach to reserve criterion, if still appropriate may be improved at minimum cost. In addition, NLH should continue their on-going efforts to include the modeling of external markets in Strategist to capture both the reliability benefits and market value of market interactions. In order to

[14] Newfoundland and Labrador Hydro, *PUB-NLH-056* (Newfoundland and Labrador Hydro: Board Response, February 2014),1

allow for a better understanding of the potentials of economy interchange Ventyx recommends NLH continues to pursue the Network Economy Interchange ("NEI") modeling effort.

Generation Forced Outage Rates

Background

The purpose of generation forced outage rates in generation planning is to represent the probability that a specific unit will not be available for service when required. Generation Planning periodically confirms the resource adequacy of a system through detailed reliability simulations that compare the expected load profiles with specific generating unit forced outage rates and maintenance schedule to determine LOLH values. A typical unit's contribution to resource adequacy is typically a function of the unit's capacity and its equivalent forced outage rate ("EFOR"). NLH uses the convention Derated Adjusted Forced Outage Rate ("DAFOR") which is known as EFOR as used by the North American Electric Reliability Council[15]. For the purposes of this report EFOR and DAFOR have the same meaning. A unit's equivalent forced outage rate is defined according to the following formula:

[15] Roy Billinton, *Reliability Data Requirements, Practices and Recommendations* (Department of Electrical Engineering University of Saskatchewan) page 55.

$$EFOR = \frac{FOH + EFDH}{FOH + SH + Synchronous\ Hrs + Pumping\ Hrs + EFDHRS} \times 100\%$$

Where:

FOH – Forced Outage Hours

$EFDH$ – Equivalent Forced Derated Hours

SH – Service Hours

$Synchronous\ Hrs$ – Synchronous Condensing Mode Hours

Pumping Hrs – All hours pumped storage unit in pumping mode

$EFDHRS$ – Equivalent Forced Derated Hours during Reserve Shutdowns

For the purposes of this discussion, Ventyx focused on NLH's largest aggregate resources that drive overall system reliability, Holyrood, 465.5 MW; and Bay D'Espoir, 592 MW. These two plants comprise 1057.5 MW and represent 54.3% of NLH's installed capacity. The EFOR used in NLH's generation planning and serving as an input to Strategist is derived from the Canadian Electrical Association's ("CEA") 2004 Report and is based on the period from January 1, 2000 through December 31, 2004. Ventyx compared these rates to the current CEA data covering the period from January 1, 2008 through December 31, 2012. NLH's other smaller CT's and Hydro units have less impact upon reliability.

Table 3 lists the five year CEA capacity weighted average EFOR based on the most recent CEA data and the EFOR assumptions in NLH's Strategist database.

Unit Name	NLH Strategist Assumptions	NLH Average 2008 - 2012
Holyrood	9.64%	10.69%
Bay D'Espoir	0.91%	0.41%

Table 3

Conclusion

NLH's overall assumptions are consistent with industry standards. While there might be some rationalization that a significant increased investment might improve Holyrood performance further, given the time until the infeed is realized, the age of the units and outage availability it appears that the time required to gain results will be longer than the relatively short timeframe to interconnection with the North American Grid.

Recommendation

Since Holyrood is scheduled to be retired in the next 4 to 5 years NLH should model its EFOR close to the actuals currently being experienced with sensitivities on either side of the expected value. With respect to all other thermal units in the Strategist model (existing and future) NLH should continue its practice of modeling with a more conservative estimate of EFOR for the units. However, one refinement that NLH could make to its EFOR assumptions would be to tie the level of EFOR to typical maintenance cycles. There is an inherent relationship between higher capital expenditures and maintenance corresponding to lower EFOR. However, it should be noted that a five year rolling average will also account for these cycles. By ramping up the EFOR, in the years leading up to a major maintenance cycle, NLH would have a better picture of the near-term, one to five year, view of system reliability.

Alternatively, NLH could also compute a break-even EFOR for each class of its generation resources. For example consider the Holyrood Plant, for which the maximum EFOR would be between 9.7% and 9.8%. At this point, the units' contribution to LOLH would exceed 2.8 hours/year.

Scenario Planning

Background

The purpose of this part of the review is to examine the NLH planning process with respect to accepted utility practices and procedures. The standard that the NLH planning process was compared is the Ventyx Integrated Resource Planning ("IRP") process. This process was developed and used by Ventyx n its worldwide consulting practice.

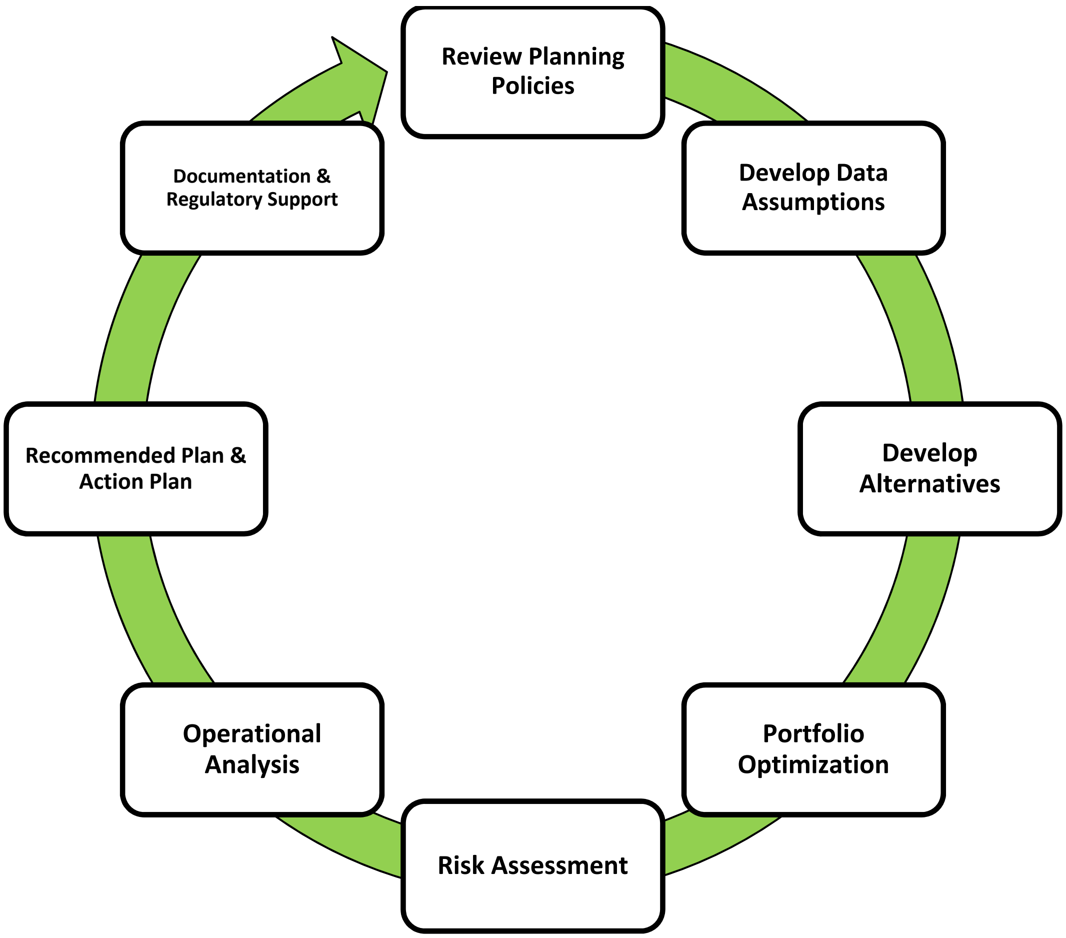

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Figure 2 IRP Planning Process

Description of each step:

- **Planning Policies Review** – This is the initial IRP project planning step in which the objectives of the IRP are set up. This includes the review of all of the rules and constraints that must be met in performing the planning process
- **Data Assumptions** – In this step all of the data assumptions are gathered and vetted. This includes the operating assumptions of all existing and proposed future alternatives, commodity prices, environmental and market prices, and transmission limits.
- **Develop Alternatives** – The simulation models for the various alternative Demand-side, Supply-side and market/transmission options are developed.
- **Portfolio Optimization** - In this step the potential resource alternatives are pre-screened using economic and operational methods. Through the use of optimization software, such as Strategist, one or more optimal plans are developed that meet a set of defined attributes and constraints.
- **Risk Assessment** - This step takes optimized plans from alternative scenarios and subjects them to sensitivity analysis to determine the impact of changes in assumptions to results. This step also determines the robustness of optimal plans to statistical distributions of sensitive variables. Then using multi-criteria decision making analysis techniques determines the trade-off between competing attributes such as risk and least cost.
- **Operation Analysis** – Selected plans are then further analyzed in terms of financial viability and operational constraints such as hydrological studies.
- **Recommended Plan and Action Plan** - The results of all the above steps is a recommended plan that the utility wished to present as its integrated resource Plan. In conjunction with this overall long –term plan an Action Plan is developed that focuses on the decision period in which actions must be decided on today. With-in the Action Plan a set of signposts are developed from the sensitivities that determine which variables should be monitored, at what value an action should be triggered, and what the contingent actions should be.

- **Documentation and Regulatory Support** –The heart of the IRP is the final documentation. These are the documents that will be filed with regulators and all other parties. It should be thorough, accurate and defendable. Note that this step is best performed as the overall IRP process is being performed.

The review of the resource planning process included a review of the original filings with the Board concerning the Muskrat Falls Project, review of two independent detailed reviews of the project, a review of the responses to the Board's questions concerning the incidents this winter, and one-on-one interviews with both NLH and NP planning staff.

Conclusions

The resource planning process being performed by NLH conforms to the basic structure laid out in the Ventyx IRP process. All areas in the IRP process were deemed as being acceptable. However, two areas, Alternative development, and Risk Assessment were found to be acceptable but in need of improvements.

In the development of alternatives it was found that although existing demand-side programs were included in the development of the resource plan there was a lack of additional demand-side alternatives. The report only mentions the presentation of CDM alternatives to the Board, no mention of the use of demand-side as alternatives to supply resources is made. Due to slow growth requirements of demand programs the use of demand-side alternative will not be effective to solve short-term issues. It will also not change the need for the capacity and energy from the Muskrat Falls project long term. However, it is Ventyx's recommendation that the use of demand-side alternatives be further explored in the period post 2017 while there is ample capacity to cover requirements. In reviewing the documents it was noted that there is no formal risk assessment being performed.

Sensitivities were performed and included in the original documentation but focused mostly on commodity and costing assumptions. Future scenario and sensitivity processes should be expanded to include the impacts of extreme loads. These expanded sensitivity analysis can then be formally included into a risk analyses process to determine the robustness and impacts of resulting plans. The additional load sensitivities are discussed above in the section on load forecast.

Recommendations

It is noted that while NLH's Resource Planning processes meets the overall IRP process requirements, there are two areas that could be incrementally improved.

Improve the resource planning process by:

- Beginning to explore the use of demand-side programs as long-term alternatives to future supply–side alternatives post 2017 and
- Expand the Risk Analysis sensitivities to include several levels of load forecast uncertainty.

Generation Outlook 2014 to 2017

On January 17th, the Board initiated a process to gather information from NLH and NP with a focus on whether load requirement on the Island Interconnected system can be met in the near term. In the near term, NLH's current resource expansion plan is within the reliability criteria.

	Loss of Load Hours (Hours)	Reserve Margin (Percent)
2013	0.97	16.32
2014	2.59	12.28
2015	3.98	10.32
2016	2.73	12.21
2017	2.68	11.00

The previous table is based on the assumption that a new 50 MW CT is in service December of 2015. If that unit does not achieve that commission date the LOLH would increase to 4.57.

NLH is currently considering six options[16] for meeting the expected LOLH in 2015. Each of these options offers the possibility to reduce the system LOLH.

1. Retain the 16 MW (10 MW to the system) diesel facility at Holyrood;
2. Review what is needed to make the remaining 4.6 MW of diesel power at Holyrood available to the system by plant modifications to increase equipment ratings to deliver 14.6 MW capacity;
3. Enter into interruptible contracts with large Industrial customers;
4. Seek already built combustion turbines in the 50 to 100 MW range to supply deficit and blackstart;
5. Initiate the supply of a new 60 MW (nominal) combustion turbine for the Holyrood site to supply deficit and blackstart; and
6. Continue and possibly enhance conservation and demand management initiatives, with the focus on demand management.

The new 60 MW (nominal) combustion turbine or other combustion turbine options are key resources for NLH's near term reliability of supply. The current plan has this unit commissioned in December of 2015. Without this unit, NLH would face LOLH reliability indices of 4.57 hours/year in 2015, 6.02 hours/year in 2016, and 5.71 hours/year in 2017, the Labrador Infeed is in service in December of 2017.

Statistically, demand reduction is a slightly better alternative to generation additions due to inherent uncertainty of generation forced outages. In order to reduce the expected 2015 LOLH of 3.98 hours/year to 2.80 hours/year, NLH would need to secure approximately 40 MW of either interruptible contracts with existing customers or conservation and demand

[16] Newfoundland and Labrador Hydro, *PUB-NLH-062* (Newfoundland and Labrador Hydro: Board Response, February 2014)

management initiatives. If that is not practical, then the difference can be made up from the remaining generation capacity options.

Furthermore, NLH uses reasonable estimates for generation forced outage assumptions as compared to Canadian Electricity Association (CEA) five year averages and the five year averages for its own equipment. The assumptions in Strategist are based upon data collected between 2000 and 2004. The generation forced outage assumption for Holyrood and Bay D'Espoir are 9.64%[17] and 0.91%[18], respectively, and they contributed to the forecast 2015 LOLH of 3.98 hours/year. Recent data from NLH operating data, from 2008 to 2012, indicates that the historical performance for Bay D'Espoir has improved to 0.41% and worsened for Holyrood to 10.69%. These figures are relatively consistent with current performance, however if the generation forced outage assumptions were improved for Bay D'Espoir, the 2015 LOLH would drop to 3.69 hours/year. If the generation forced outage assumptions were changed for Holyrood the contribution to the 2015 LOLH would increase to 4.49 hours/year.

The primary drivers are the Holyrood units. Focusing only on Holyrood, if Holyrood unit could achieve an annual forced outage rate of 8.48% or less then the system would achieve a LOLH of 2.8 hours/year. Recognizing the age of these assets this may not be practical in the short term and continuing the current assumptions is prudent planning, particular for the near term. As well there is merit in assessing some variation of this expected performance to gauge sensitivity on the LOLH result.

Summary of Recommendations

Ventyx has not found any evidence that either the generation planning process or the load forecasting process have contributed to the events of January.

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[17] Source: CEA Typical 2000-2004. Table 6.2.2 100-199 MW Classification for Holyrood.

[18] Source: NLH Operating Experience between 2000-2004. Weighted Average based on Bay D'Espoir units & Hinds Lake, Upper Salmon, Cat Arm and Paradise River

It was noted above that Ventyx does not believe it is desirable to change the forecast methodology to an end-use model. Primarily this is due to the increased complexity and cost, but it is also noted above that the major end-use on the system is electric heat and is already included in the forecast model and thus capturing the majority of any additional detail accuracy benefits that would be expected from an end use model. Since the R^2 for the two regression equations involving heating penetrations were 79% and 89% it would be advisable that NLH continue to refine its models with respect to these two variables. This can be further enhanced through continued surveying of the customer base in terms of both average use and saturation of this end use.

The above discussion has been in terms of the base-case scenario. It has been recommended above that NL begin using a formal risk assessment process that includes the evaluation of plans under extreme weather conditions. As such, it will be important to develop alternative load forecast in both the scenario development and the sensitivity analysis phases.

NLH should continue to use its generation planning reserve criterion.

After completion of NLH's interconnection with Nova Scotia and Muskrat Falls, NLH should revisit their generation planning reserve criterion of 2.8 hours/year in light of the reliability benefits offered by the access to North American markets. In addition, NLH should continue their on-going efforts to include the modeling of external markets in Strategist to capture both the reliability benefits and market value of market interactions. In order to allow for a better understanding of the potentials of economy interchange Ventyx recommends NLH continues to pursue the Network Economy Interchange ("NEI") modeling effort.

Since Holyrood is scheduled to be retired in the next 4 to 5 years NLH should model it's EFOR close to the actuals currently being experienced with sensitivities on either side of the expected value. With respect to all other thermal units in the Strategist model (existing and future) NLH should continue its practice of modeling with a more conservative estimate of EFOR for the units. However, one refinement that NLH could make to its EFOR assumptions would be to tie the level of EFOR to typical maintenance cycles. There is an inherent relationship between higher capital expenditures and maintenance corresponding to lower EFOR. However, it should be noted that a five year rolling average will also account for these cycles. By ramping up the

EFOR, in the years leading up to a major maintenance cycle, NLH would have a better picture of the near-term, one to five year, view of system reliability.

Alternatively, NLH could also compute a break-even EFOR for each class of its generation resources. For example consider the Holyrood Plant, the maximum EFOR would be between 9.7% and 9.8%. At this point, the unit's contribution to LOLH would exceed 2.8 hours/year.

Improve the resource planning process by:

- Beginning to explore the use of demand-side programs as long-term alternative to future supply–side alternatives post 2017 and
- Expand the Risk Analysis sensitivities to include several levels of load forecast uncertainty.

Appendices

PUB-NLH-008

PUB-NLH-011

PUB-NLH-056

PUB-NLH-062

Q. How does Hydro determine the appropriate reserve to have available to meet the Island Interconnected system load?

A. From a long-term planning perspective, Hydro has established criteria related to the appropriate reliability for the system, at the generation level, that sets the timing of generation source additions. These criteria set the minimum level of reserve capacity and energy installed in the system to ensure an adequate supply for firm demand; however, short-term deficiencies can be tolerated if the deficiencies are of minimal incremental risk. As a general rule to guide Hydro's planning activities the following have been adopted:

Capacity: The Island Interconnected System should have sufficient generating capacity to satisfy a Loss of Load Hours (LOLH) expectation target of not more than 2.8 hours per year[19].

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[19] LOLH is a statistical assessment of the risk that the System will not be capable of serving the System's firm load for all hours of the year. For Hydro, an LOLH expectation target of not more than 2.8 hours per year represents the inability to serve all firm load for no more than 2.8 hours in a given year.

Energy: The Island Interconnected System should have sufficient generating capability to supply all of its firm energy requirements with firm system capability[20].

From an operational perspective, Hydro manages generation resource availability on the Island Interconnected System and schedules generating units out of service for planned maintenance in order to meet a (n-1) system contingency reserve criterion. In this manner, sufficient reserves are planned to be available to meet the Island Interconnected System load under a contingency of the largest (MW rating) available generating unit. Hydro does not rely on capacity from wind and other non-dispatchable[21] resources to provide reserve. However, if these resources are in production they can further increase the reserves available. Following the (n-1) criterion results in no extended planned maintenance scheduled during the winter period. However, if the short-term load forecast permits, Hydro may take the opportunity to schedule a short duration generating unit outage to address running or corrective maintenance issues.

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

[21] Please refer to PUB-NLH-044 for a definition of "non-dispatchable".

Q. Provide the forecast and actual peak demand for each month in the winter period in each year from 2004 to 2013 and the forecast each year for 2014 to 2017 for each month in the winter period.

A. Please see below for the forecast and actual peak demand supplied by Hydro for the Island Interconnected System. Please note that Hydro interprets the winter period to be from December through March and that the forecasts provided are Hydro's Operating Load Forecasts. Please refer to Hydro's response to PUB-NLH-014 on timing of preparation.

Island Interconnected System Supply Issues and Power Outages

NLH System Peak Demand (MW)

	Forecast	Actual
Jan-04	1399	1277
Feb-04	1338	1405
Mar-04	1237	1206
Dec-04	1374	1402
Jan-05	1429	1361
Feb-05	1405	1272
Mar-05	1301	1161
Dec-05	1353	1202
Jan-06	1385	1276
Feb-06	1369	1185
Mar-06	1256	1167
Dec-06	1333	1310
Jan-07	1358	1323
Feb-07	1350	1249
Mar-07	1238	1242
Dec-07	1336	1286
Jan-08	1367	1289
Feb-08	1356	1212
Mar-08	1242	1207
Dec-08	1350	1323
Jan-09	1388	1390
Feb-09	1377	1375
Mar-09	1262	1294
Dec-09	1349	1268

NLH System Peak Demand (MW)

	Forecast	Actual
Jan-10	1372	1253
Feb-10	1361	1305
Mar-10	1243	1142
Dec-10	1371	1207
Jan-11	1401	1278
Feb-11	1390	1292
Mar-11	1270	1200
Dec-11	1405	1399
Jan-12	1433	1385
Feb-12	1417	1350
Mar-12	1302	1341
Dec-12	1432	1307
Jan-13	1461	1378
Feb-13	1446	1374
Mar-13	1332	1272
Dec-13	1401	1501
Jan-14	1478	-
Feb-14	1429	-
Mar-14	1322	-
Dec-14	1425	-
Jan-15	1523	-
Feb-15	1470	-
Mar-15	1361	-
Dec-15	1447	-
Jan-16	1543	-
Feb-16	1498	-
Mar-16	1383	-
Dec-16	1466	-
Jan-17	1567	-
Feb-17	1515	-
Mar-17	1395	-
Dec-17	1473	-

Note: Forecast and actual peaks reflect gross requirements.

Q. Further to the response to PUB-NLH-008, state the date(s) the criteria used for generation source additions was last reviewed by Hydro. In the response state whether Hydro is of the opinion it should be reviewed in light of Hydro’s aging infrastructure and when is the appropriate time to review this criteria.

A. Hydro’s generation source additions criteria have been in use for over 35 years and in that period they have been reviewed on a number of different occasions and found to provide a good balance of reliability versus cost.

Before 1977, there were no approved long-term reliability criteria for generation planning in Hydro. The basis of the current criteria is a report, *Recommended Loss of Load Probability (LOLP) Index for Establishing Generation Reserve Additions*, System Planning Department, May 16, 1977. In that report, a LOLP of 0.2 days per year, or 1 day in 5 years was established. In 1997, when Hydro replaced the SYPCO generation planning software with ProScreen II (now renamed Strategist) generation planning software, it was necessary to switch to a Loss of Load Hours (LOLH) criterion. Benchmarking established that a LOLH of 2.8 hours per year was equivalent to a LOLP of 0.2 days per year, for Hydro’s system. From that point onward, Hydro established the capacity criteria that the Island Interconnected System should have sufficient generating capacity to satisfy an LOLH expectation target of not more than 2.8 hours per year.

In 1991, at the direction of the Board, George C. Baker, a consultant working for Hiltz and Seamone Company Limited carried out a study and produced a report -*Report on the Technical Performance of Newfoundland & Labrador Hydro* - October 2, 1991. On page 9 of the report, in Section *7 System Planning,* it states:

Hydro uses two criteria for generation planning in its interconnected system.

(a) Sufficient production capacity to meet all needs under firm water conditions (lowest recorded flows), and

(b) A loss of load expectancy of one day in five years.

The first criterion is usual for utilities with significant dependence on hydraulic generation. The second differs from the one-day-in-ten-years LOLE[22] *adopted by many utilities.*

The main reason for permitting a higher LOLE is economic. Hydro, unlike almost every other major utility, is an isolated system. Other utilities can, and do, rely on capacity support from interconnected utilities in meeting the one-day-in-ten-years criterion. Hydro cannot do this, and would have to maintain a much higher generation reserve.

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[22] Loss of Load Expectation. LOLE is another way of stating LOLP and the two are equivalent.

Hydro believes the costs of doing so would not be justified by the difference in reliability. The Consultant agrees.

In 1999, at the direction of the Board, Quetta Inc. and Associates carried out a study and produced a report *Technical Review of Newfoundland and Labrador Hydro Final Report* March 17, 1999. On page 23 of the report, in Section *2.1.3.2 Capacity*, it states:

The Island Interconnected System should have sufficient generating capacity to satisfy a Loss of Load Expectation (LOLE) target of not more than 2.8 hours per year. This is equivalent to 0.2 days/year or 1 day in five years. It results in a capacity reserve requirement of 18%.

The LOLE capacity criterion is somewhat less stringent than that employed by large interconnected systems in the rest of North America (one day in 10 years or 0.1 days/year). Considering the non-interconnected status of the Island's electric utility system, (reserve sharing is not an option) the cost of providing higher reliability level is probably in excess of the benefits to be derived.

Quetta is of the opinion that the capacity and energy criteria are reasonable in the circumstance.

Most recently, the criteria were reviewed in the *Report on Two Generation Expansion Alternatives for the Island Interconnected Electrical System – Volume 2: Studies January 2012*. This report was prepared for the Board by Manitoba Hydro International. In the report, *Section 3 – Reliability Studies* runs from page 57 to page 71. *Section 3.11 – Conclusions and Findings*, page 70, states the following:

Available documentation for reliability assessment performed by Nalcor has been reviewed by MHI. The adequacy criteria of 2.8 hours/year of loss of load expectation for resource planning, which considers both generation resource availability and economics, appears reasonable when compared to practices of other operating utilities.

As part of its internal review of recent events, Hydro has engaged an outside consultant (Ventyx) to review its generation planning practices. One of the areas to be reviewed is the criteria used for generation source additions. As well, in light of Hydro's aging infrastructure, it is also appropriate to review the inputs to the generation expansion model, such as the current and expected forced outage rates of Hydro's generating units. These will also be reviewed.

Q. Further to the response to PUB-NLH-018, which states that there is a capacity deficit identified for 2015, explain in detail each of the "*several generating options potentially available to meet winter peak demand*" that Hydro stated it was pursuing, including the status of the review of each option and the time required to construct or install each option.

A. The options under consideration for meeting the deficit currently expected in 2015 include the following and may be a combination of two or more to meet the potential deficit:

1. **Retain the 16 MW diesel facility at Holyrood (presently under a lease-to-own arrangement).** Once installed, 10 MW can immediately be supplied to the system on a sustained basis. This facility is currently being prepared for commissioning in early March 2014.
2. **Review what is needed to make the remaining diesel power available to the system.** Please refer to Hydro's response to PUB-NLH-064.
3. **Enter into interruptible contracts with large Industrial Customers.** Discussions with Industrial Customers (CBPP, Vale and North Atlantic Refining) were initiated in fall 2013. These discussions are ongoing and options continue to be explored. Please refer to Hydro's response to PUB-NLH-050.
4. **Seek already built combustion turbines in the 50 to 85 MW range**. Preliminary discussions indicate that these options can provide in-service to meet the 2015 requirement. However, discussions with manufacturers, brokers and owners are

ongoing to determine the delivery times, operating experiences, the extent of modifications required, and the facilities required to connect to the Island Interconnected System.

5. **Initiate the supply of a new 60MW (nominal) combustion turbine for the Holyrood site to supply deficit and blackstart functionality.** All preliminary engineering is complete. With final approval by June 2014, this plant could be in-service by 2015.
6. **Conservation and demand management initiatives, with the focus on demand management**. Work is being conducted to assess customer end use options with a view of providing demand management. This is considered a supplemental means of meeting the deficit and may provide further cost savings opportunities when combined with other options.