newfoundland labrador
hydro
a nalcor energy company

Hydro Place. 500 Columbus Drive.
P.O. Box 12400. St. John's. NL
Canada A1B 4K7
t. 709.737.1400 f. 709.737.1800
www.nlh.nl.ca

October 31, 2014

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

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

Dear Ms. Blundon:

Re: The Board's Investigation and Hearing into Supply Issues and Power Outages on the Island Interconnection System

In accordance with the Board's Interim Report dated May 15, 2014, wherein the Board required the filing of a report by today's date with respect to the above-noted matter, please find enclosed the original plus 12 copies of Hydro's report entitled *Progress Report on Load Forecasting Improvements.*

Should you have any questions, please contact the undersigned.

Yours truly,

NEWFOUNDLAND AND LABRADOR HYDRO

Geoffrey P. Young
Senior Legal Counsel

GPY/jc

cc: Gerard Hayes – Newfoundland Power
Paul Coxworthy – Stewart McKelvey Stirling Scales
Thomas Johnson – Consumer Advocate
Danny Dumaresque
ecc: Roberta Frampton Benefiel – Grand Riverkeeper Labrador

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

A Report to the Board of Commissioners of Public Utilities
Progress Report on Load Forecasting Improvements

Newfoundland and Labrador Hydro

October 31, 2014

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1.0 INTRODUCTION

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

The inability of Hydro to meet full system load was, in part, because of unavailability of sufficient generation supply. Several unplanned generation outages in the last half of December, 2013, involving five different generating facilities, resulted in a supply deficit of approximately 230 MW. Hydro's internal review and investigation of the supply disruptions identified a number of actions to be taken to address the factors which caused this generation deficit. Many of these actions have been completed, and others are due for completion in advance of the 2014/15 winter season. Hydro has been providing regular update reports to the Board of Commissioners of Public Utilities (the Board) in relation to its generation winter readiness action planning.

An additional factor which significantly influenced load in late December 2013 and early January 2013 was weather. The 2013/14 winter period was not the norm in that the winter peak demand occurred earlier than usual. Low temperatures experienced in the last half of December and into early January were more severe, and more sustained, than normal.

In the course of its investigation, Hydro also reviewed its processes for forecasting peak system loads, as well as the processes and systems used to forecast system load growth and future generation and reserve requirements. With the help of external experts in these areas, Hydro identified a number of actions it would take to improve its forecasting processes. Additional recommendations made by Liberty Consulting in their April 25, 2014 report to the Board were adopted by Hydro as well, and all actions were incorporated into Hydro's Integrated Outage Action Plan.

In its Interim Report of May 15, 2014, the Board indicated two priority actions it felt were required in relation to load forecasting and generation planning. This Report is in response to the Board's request that Hydro file a report by October 31, 2014 in relation to the changes Hydro has made to its short-term forecasting process and its approach to the incorporation of sensitivity analyses in its supply forecasting and planning decisions.

2.0 BACKGROUND

Hydro's forecasting processes were not found to be a contributing factor in the January 2014 supply disruptions, however, reviews completed internally and by Ventyx, and the preliminary reports completed by the Liberty Group and the Public Utilities Board highlighted several recommendations with respect to improving Hydro's load forecasting processes. In response to these recommendations Hydro undertook reviews of its short term hourly, monthly and long term planning forecasting methodologies and their corresponding data sets.

Hydro has three different load forecasts that it uses to plan and operate the power system:

- **System Operations Short-Term Forecast** - has a time frame of seven days. The time step is hourly and the forecast is prepared six times a day. The System Operations forecast is used for generating unit scheduling and equipment outage approvals. 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.

- **Medium-Term Operating Load Forecast** - 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. The Operating Load Forecast is used for budgeting and medium-term operational planning, such as equipment outage planning and hydro-thermal optimization. The Operating Load Forecast 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 Powers' peak demand forecast methodology was developed in consultation with Hydro.

- **Long-Term Planning Forecast** - typically has a time horizon of 20 years. The time step for the long-term planning forecast is one year and the forecast is prepared annually. This forecast is used for assessing the long-term reliability of the Island Interconnected system and for planning resource requirements to meet reliability criteria. 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.

3.0 SYSTEM OPERATIONS SHORT-TERM FORECAST

The Ventyx Nostradamus model is used for short term (one to seven days) load forecasting with an hourly time step. Nostradamus is a neural network algorithm which learns the pattern of load changes from weather variables, day of week, time of day, etc. by learning from historical data from training and then verification periods. The forecast is used by System Operations to assist in determination of generation reserves, unit commitment and scheduling, and equipment outage assessments.

In late December 2013 System Operations noted that Nostradamus was not accurately predicting the load, likely because of the low temperatures and high winds experienced at the time. This continued into early January 2014. Because the forecasts are based on historic patterns of weather and load, the model can have difficulty predicting load during conditions outside of its learning dataset. For parts of most days the forecast was reasonable but there were occasional patterns that were inaccurate.

In its review of the supply issues and power outages on the Island Interconnected System for the Public Utilities Board, Liberty made the following recommendations with which Newfoundland and Labrador Hydro concurred.

1. Hydro should complete the modifications or replacement of Nostradamus by December 1, 2014 in order to enable improvements in the accuracy of short-term forecasts under extreme weather conditions.
2. By December 1, 2014, Hydro should incorporate into its short-term forecasting process any significant load changes, from losses or otherwise, resulting from varying system configurations.

Hydro's internal review concluded that factors related to load forecasting did not result in decisions that contributed to the supply disruptions or rotating outages. There was, however, a recommendation to improve short-term forecasting during cold weather. More accurate forecasting could improve Hydro's ability to manage and communicate during outages and emergencies by providing System Operations and Energy Control Centre Operators with more accurate estimates of expected peak loads.

System Operations developed a work plan as part of Hydro's Integrated Action Plan (IAP) to address Hydro's identified actions and the recommendations from Liberty and the Public Utilities Board. The work plan involves the implementation of enhancements to the short term forecasting model to ensure a better correlation in extreme cold weather conditions and includes five main tasks:

- Hold training/workshop with Ventyx's Nostradamus application subject expert;
- Implement and test new training parameters and procedures;
- Make database changes required to implement the new version;
- Design and implement new island forecasts; and
- Move new software and model to the Production environment.

The target date for completion of the work plan was October 31, 2014. The schedule targeted to have all work essentially complete by late September so that some experience could be gained with the new model well in advance of the move from development to production. Difficulties with the Nostradamus software database, which required intervention by the vendor, delayed completion of some of the tasks and to date the newer version of the software and model have not been implemented on the Production environment. Implementation on the Production environment is expected to be completed before the final week of November.

As part of its standard work plan, Hydro reviews the accuracy of the Nostradamus forecasts on a quarterly basis and does re-training of the model if required. For the winter of 2014/2015, the frequency of this review will be increased to monthly.

3.1 Nostradamus Improvements Status Update

3.1.1 Ventyx Training/Workshop

A Ventyx representative held a workshop at Hydro's offices in June, 2014. The objectives for the workshop were to:

- Train additional staff to be familiar with Nostradamus;
- Improve the load forecast to be able to plan generation and identify potential system demand shortages in advance;
- Provide better understanding of how the Nostradamus model works to allow ongoing improvements to the forecasts;
- Troubleshoot problems with communications between Nostradamus and other Energy Management System (EMS) databases; and
- Understand how to test forecast training with specific historic periods of unusual load (e.g. January 2014).

Seven employees from Hydro participated in the workshop. A new version of the Nostradamus model (Version 8.2) was installed on Hydro's Development environment and the key features of the model were reviewed and demonstrated. The interactive nature of the workshop enabled some changes to be made to Hydro's model during the workshop.

Recommendations by Ventyx to improve Hydro's implementation of Nostradamus included:

- Investigate cloud cover as a training parameter;
- Investigate a three-day moving-mean temperature as a training parameter to model the load effects of persisting hot or cold weather;
- Investigate a daylight training parameter (0 for dark, 1 for light and a value between 0 and 1 for dawn or dusk);
- Limit the training period to one to three years – this differs from the 'the more, the better' advice previously provided;

- Consider reducing the number of meteorological stations used; using more stations slows down training and execution of forecasts and may not add;
- Vary the verification period used during model training, as it too is used in deriving the model parameters;
- Put an emphasis on data quality (meteorological and demand) as poor data can have a significant effect on training and forecasts, especially with intraday forecasts;
- Replace demand data during major outages with forecast model values for that period; and
- Increase the frequency of forecasting 'today's' load and consider getting multiple weather forecasts and observed data reports daily.

During the workshop, Ventyx confirmed that Nostradamus has the following limitations that can reduce the accuracy of its load forecasting:

- Nostradamus cannot forecast load if meteorological conditions are different from those during the training period, and
- Nostradamus cannot forecast load growth.

Both limitations stem from the nature of neural network models – all forecasts are based on patterns derived during analysis of historic data. Since historic data comprises only actual load and prior weather conditions, Nostradamus may not accurately forecast load during unusual or infrequent weather conditions and will not reflect any growth in load. Recommended practices to account for these limitations have been developed which will now be used.

3.1.2 Implement and Test New Training Parameters and Procedures

Since the workshop with Ventyx in June, significant effort has been expended to incorporate Ventyx's recommendations into Hydro's short term forecasting. To date, these changes have been made only on Hydro's Development environment. Comments on the individual recommendations are provided below.

Investigate cloud cover as a training parameter. Cloud cover data are generally only available at major climate stations; on the Island it is only available for St. John's, Gander, Deer Lake and Port aux Basques. Previously, Hydro used nine stations on the island to represent weather conditions: those listed above plus St. Lawrence, Stephenville, Badger, Daniel's Harbour and St. Anthony. Because Ventyx also recommended reducing the number of stations used for forecasting, recent work has used only the stations where cloud cover data are available.

Investigate a three-day moving-mean temperature as a training parameter. Some work was done on this parameter during the workshop but it was not found to improve the forecasting accuracy, so this recommendation was not given priority in the current exercise. This parameter will be investigated further once time allows.

Investigate a daylight parameter. An 'actual' data series has been developed for 2011 through 2016 which represents dark hours as 0, daylight hours as 1 and dawn and dusk hours as values between 0 and 1 based on sunrise and sunset hours. Since this parameter is known in advance, forecasts are not required.

Limit the training period to one to three years. Previous guidance from Ventyx had been to use as much data as possible, back to the last significant change in the load, so Hydro was using data from April 2009, when the Grand Falls Paper Mill closed. Recent training has been done using data since January 2012.

Consider reducing the number of meteorological stations used. This recommendation was discussed above.

Vary the verification period used in training. Work on this recommendation has yet to be completed. Most recent training has used the period 1 January 2014 to 31 May 2014 for verification but this will change when the latter part of 2014 is added into the training period.

Put an emphasis on data quality (meteorological and demand). All temperature, wind speed and cloud cover data used in training has been closely examined to eliminate erroneous data and to fill in missing data. Preliminary checks have been done on the demand data, but additional screening may still be required. As well, the Nostradamus training process will help to identify errors in the demand data.

Replace demand data during major outages with forecast model values for that period. Hydro's previous practices had been to replace load data from periods of major outages with data from the previous and/or subsequent day. Ventyx recommended, instead, using data from the Nostradamus forecast. This was done during the workshop for the January 2014 supply disruption period as a training exercise but will need to be repeated for January 2014 with the new Avalon and Island load definitions and for other outage periods, as required. It is somewhat of an iterative process as replacing the outage load with a more realistic value will improve subsequent training and forecasting.

Use Nostradamus to forecast conforming (weather dependent) load only. This recommendation was part of Hydro's work plan prior to discussions with. It is discussed in a later section of this report.

Increase the frequency of forecasting 'today's' load. Previously the load forecasting model was run six times a day. The model on the Development environment is currently running in automatic mode every hour. Forecasts after 6 AM differ only in the actual demand data used, as it is imported every hour. Currently the weather forecast is only obtained once per day, but the Request for Proposal recently issued to renew Hydro's weather forecasting services asks for costs for both once and twice per day. An additional weather forecast issued midday may improve the forecast of the supper hour peak.

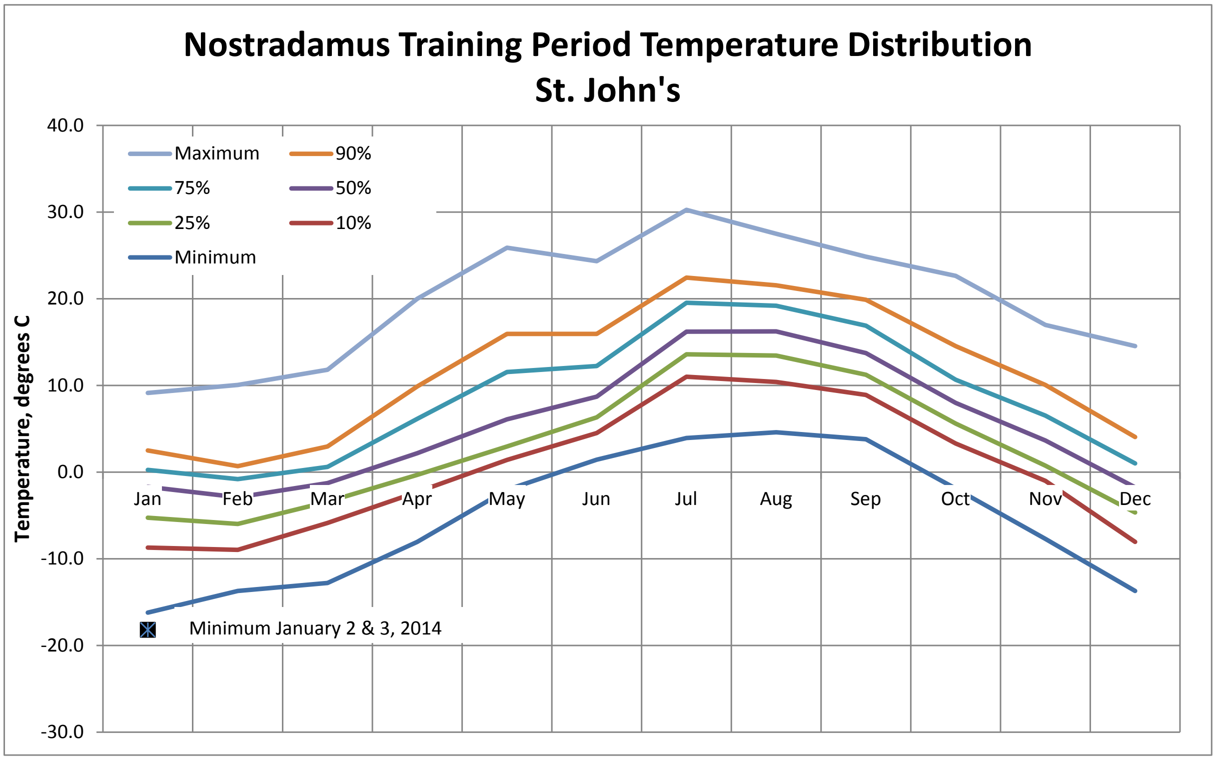
Forecasting Procedures

As noted above, Nostradamus cannot forecast for load or weather that was not experienced in the training period, so Hydro is implementing new practices to account for these limitations.

To assist System Operations and the Energy Control Centre in identifying when weather conditions are unusual for the time of year, plots of temperatures and wind speeds experienced during the current training period will be prepared. An example of this kind of plot can be seen in Figure 1 below, for temperatures from 2011 to 2013 inclusive. Any forecast minimum temperature can be compared to the plot to gauge how well Nostradamus is likely to forecast the load. As seen on the plot, the temperatures in January 2014 were clearly outside the range used for training, so Operators would know that Nostradamus would likely underestimate load. These plots will need to be revised every time the period used to train the Nostradamus model is modified.

Prior to implementing the new model on the Production environment, Nostradamus will be trained using data from January 2013 and 2014 with the expected loads estimated by the forecast model, so if similar temperatures are experienced in 2015, Nostradamus will be able to forecast the load with improved accuracy.

Figure 1



A process has been created for System Operations engineers to forecast industrial load outside of Nostradamus and have it added to the forecast prior to presentation. Using the same software tool, System Operations engineers will be able to input an offset for any hour(s) of the seven-day forecast graph to reflect any information, including meteorology, losses or load, that they feel will not be accurately represented in the Nostradamus model.

3.1.3 Database Changes

Prior versions of Nostradamus used Excel and Access to import data into Nostradamus and to create tables and plots of the load forecast. The newer Nostradamus versions do not allow the use of Access and provide some improved techniques for data input and output so that Excel macros are no longer required.

These software changes have no effect on the accuracy of the forecast, but work was required to ensure that data was being routinely input to the model and that forecasts could be obtained in the appropriate format for use by System Operations personnel.

3.2 Representation of System Losses

In considering the transmission losses on the Island Interconnected System, the transmission and generation configuration is important. Geographically, the hydroelectric generation is located in Bay d'Espoir and west. The Holyrood Thermal Generating Station (HTGS) is located on the Avalon Peninsula in the east. The largest load center on the Island Interconnected System is located on the Avalon Peninsula. Consequently, under normal operation at time of peak with the HTGS on line, in close proximity to the largest load center, total transmission losses are minimized. Under existing loads and normal dispatch total transmission system losses during peak load conditions will equal 50 to 55 megawatts (MW).

During the January, 2014 events it was found that the system losses exceeded the expected level, by approximately 30 to 40 MW because the generation dispatch on the Island was not typical for the period. In essence, with the full capacity of the HTGS not available, additional generation capacity off the Avalon Peninsula was required to supply Avalon load. Increasing the current flow over the longer transmission path resulted in increase transmission system losses.

To assist the Short-Term load forecast process with representation of transmission system losses, Hydro has initiated an analysis of the transmission system loss variation on the Island Interconnected System for "off nominal" generation dispatches.

This analysis included the following steps:

- Develop a set of base case load flows using typical generation dispatches. Load flow cases with system loads ranging from 600 MW to peak loads in 50 MW steps have been developed to capture the operating range of the three units at Holyrood.
- Tabulate the base case total transmission system losses.
- For each load flow case (e.g., 1400 MW system load) remove one unit at Holyrood from service and replace with alternate generation. The available generation includes the new Holyrood CT (120 MW), Hardwoods and Stephenville CTs (50 MW each) and the 60 MW interruptible contract with Corner Brook Pulp and Paper. Two alternate generation replacement scenarios were considered for impact on losses. Scenario A considered replacement of the lost Holyrood unit capacity with Holyrood and Hardwoods CTs first followed by off Avalon generation. Scenario B considered replacement of the lost Holyrood unit capacity with Hardwoods and Stephenville CTs and the 60 MW interruptible contract.
- Tabulate the total transmission system losses for the contingency cases.
- Calculate the incremental transmission system losses due to the generation contingency and replacement generation scenario by subtracting the base case transmission system losses from the contingency transmission system losses.
- Repeat the load flow analysis for loss of two units at Holyrood to determine the incremental transmission system losses for this contingency.
- Repeat the incremental transmission loss analysis for 230 kV transmission lines contingencies east of Bay d'Espoir using the approach described above.
- Tabulate the incremental losses versus system load for each contingency in a matrix.

The analysis to determine incremental transmission system losses is underway. To date the base case losses and the Holyrood generation contingency outage losses have been determined. The outcome provides the incremental transmission system losses for the contingencies. Table 1 provides the <u>draft</u> matrix for use in short term load forecasting to account for generation contingencies. Work continues to develop the incremental transmission system loss matrix for the 230 kV transmission line contingencies. The work will be complete before the last week in November.

As noted in Section 3.1.2, the new offset will allow the System Operations engineers to adjust the load forecast to reflect the changes in losses resulting from the different generation dispatch.

Table 1 2015 Transmission System Losses Matrix - DRAFT Holyrood Generating Unit Contingencies				
Gross Island 60 Hz Generation MW	Typical HRD Units	Base Case Losses MW	Loss One HRD Unit Incremental MW	Loss Two HRD Units Incremental MW
1700	3	64.3	22.4	34.7
1650	3	56.6	18.1	27.7
1600	3	50.3	15.3	23.6
1537	3	44.9	13.3	20.5
1483	3	40.3	11.8	18.3
1429	3	36.5	10.5	16.3
1376	3	33.1	9.5	14.9
1323	3	30.3	8.7	13.7
1271	3	28.1	7.8	12.8
1219	3	26.3	7.7	12.6
1174	2	31.2	13.7	21.0
1121	2	28.7	12.6	18.6
1067	2	26.3	11.9	17.8
1028	1	35.8	19.9	N/A
975	1	32.1	18.9	N/A
921	1	28.2	17.8	N/A
869	1	26.5	16.1	N/A
832	0	39.8	N/A	N/A

Notes:

1. Loss values are based upon 2015 peak load distribution.
2. All loss values are net of Holyrood Station Service.
3. Loss of one 170 MW Holyrood unit with capacity made up by the Holyrood CT at 120 MW and Hardwoods CT at 50 MW results in approximately 2 MW decrease in total transmission system losses due to the Hardwoods CT being located at the load center (Scenario A).
4. Loss of one 170 MW Holyrood unit with capacity made up of the Hardwoods and Stephenville 50 MW CTs and the 60 MW Corner Brook interruptible contract leaves the Holyrood CT in reserve with increase in transmission system losses as noted (Scenario B).
5. Loss of 340 MW capacity for the loss of two Holyrood units requires the startup of all standby thermal generation and the 60 MW interruptible contract.

3.3 Approach to Avalon and Island Forecasts

Following the supply disruptions in January, changes have been made to the way the Hydro load is reported. There will no longer be a distinction between System (Hydro) load and Island (including Newfoundland Power and Corner Brook Pulp and Paper) load. Avalon load will still be presented separately as it is required for assessing the commitment of generating units at the Holyrood Thermal Generating Station. Secondly, Ventyx confirmed Hydro's decision to use Nostradamus to forecast utility, or 'conforming', load only. Nostradamus cannot forecast industrial load as it is not a function of weather.

Appendix A describes in more detail how loads will now be defined and how forecasts will be prepared.

Changes in the Energy Management System were required to facilitate these forecast model changes. Nostradamus will be used to forecast utility load and a forecast of industrial load will be added to the Nostradamus results prior to presentation. Default values will be used for industrial load, but System Operations personnel will be able to overwrite the default values if one or more hours of one or more industrial loads are expected to be atypical. Offsets to the default load could be based on information from customers or observation of historical trends in data.

4.0 MEDIUM–TERM OPERATING LOAD FORECAST

Hydro's Medium-Term monthly load forecast for the 2013/2014 winter period predicted monthly peak loads consistently lower that actual experienced. Considerable analysis has been completed to identify the reason for this discrepancy and identify actions to improve the forecast. The following sections explain the findings.

4.1 Review of Winter 2013/2014 Weather Conditions

Owing to the significant share of electric space heating systems on the Island Interconnected System, weather plays a prominent role in the magnitude of system peak demands across the winter months. Coincident with this past winter was a series of high and record breaking system peak loads on the Island Interconnected System. Hydro's review of these events concludes that the prevailing weather conditions during the winter of 2013/2014 were a significant contributor to both the system peaks and higher loads for all winter months in general. The weather can be summarized as follows:

- With respect to daily heating load requirements, the weather[1] was substantially colder than the previous four winters and colder than the historical 30 year averages for the months of December, February and March.
- Peak demand weather[2] conditions for the mid-December through the end of the Christmas holiday period were significantly colder than had been experienced in the past 18 years and had not been as severe since 1984.
- The peak demand weather conditions in January were more severe than average historical and P50 (50th percentile) weather conditions and occurred earlier in the month than normal.
- Peak load weather conditions in February were less onerous than average historical peak weather conditions but were colder than had been experienced in the previous three years.

[1] As measured by heating degree days for St. John's, Gander and Stephenville weather stations.
[2] As measured by wind chill for St. John's, Gander and Stephenville weather stations.

- Peak load weather conditions in March were colder than had been experienced since 1992 and were equivalent to between an average and P90 (90th percentile) weather condition.
- System winter peaks have historically occurred anytime in the December through March period and should be expected to continue to do so. This information will be provided to System Operations with future forecasts.

Graphical presentations from which these conclusions have been drawn are provided in Appendix B.

4.2 Review of System Load during the Supply Disruption

As weather conditions during the January 2014 supply disruptions were consistent with average long term peak load weather conditions, it was important to quantify the peak loads that would have materialized on the system had supply disruptions not occurred. Quantifying the normalized peak demand for the period can also establish if unusual load events had occurred. The tables below present the estimated peak loads for both the Island Interconnected and NL Hydro systems on an actual weather (Table 2) and normalized weather (Table 3) basis.

Table 2 - Customer and System Peak Demand Estimates for January 2, 2014
(MW)

	Island Interconnected System	NLHydro System
Newfoundland Power (NP)	1411	1321
Hydro Rural	100	100
Industrial	162	48
NLH Transmission Losses	51	51
Holyrood Station Service	24	24
System Total	1748	1544

Notes: 1. Peak demand estimates are at actual weather conditions.
2. NP and Hydro Rural peak demands include Christmas season load.
3. Transmission losses reflect 2014 loads and normal supply dispatch.

Table 3 - Weather Normalized Customer and System Peak Demand Estimates for January 2, 2014
(MW)

	Island Interconnected System	NLHydro System
Newfoundland Power (NP)	1395	1305
Hydro Rural	99	99
Industrial	162	48
NLH Transmission Losses	51	51
Holyrood Station Service	24	24
System Total	1731	1526

Notes: 1. Normalized peak demand estimates are at average historical peak weather conditions.
2. NP and Hydro Rural peak demands include Christmas season load.
3. Transmission losses reflect 2014 loads and normal supply dispatch.

In the context of the Island Interconnected System, the utility loads of Newfoundland Power and Hydro Rural are considered weather dependent whereas industrial loads are considered non-weather dependent, or non-conforming. The following conclusions are based on Hydro's assessment of peak loads during the supply disruptions:

- Predicted utility peak loads of Newfoundland Power and Hydro Rural for the outage period were higher than had been forecast. This is explained by the earlier than expected onset of cold weather.
- The higher load requirements of Newfoundland Power during the outage period were consistent with the prevailing weather conditions coinciding with seasonal Christmas loads. Seasonal Christmas loads are estimated to be in the order of 20 to 30 MW.
- Industrial loads were lower than forecast because of lower demand at the nickel processing facilities at Long Harbour.
- The difference between the forecast and the actual combined winter peak demand for Newfoundland Power and Hydro Rural, on a weather normalized basis and after accounting for seasonal Christmas load was less than 2.5 percent.

4.3 Newfoundland Power Peak Demand Forecast

Newfoundland Power's peak demand forecast is a key input to Hydro's five year monthly and forthcoming winter peak demand forecasts. The Newfoundland Power forecast methodology is detailed in Newfoundland Power's response to PUB-NP-006. Stemming from the current review and in order to provide Hydro's System Operators with improved information on Newfoundland Power peaks for a given winter peak season, Newfoundland Power were requested to provide a range to their baseline winter peak demand forecast. The results of Newfoundland Power's assessment can be summarized as follows:

- Average or expected Newfoundland Power winter peak demand can vary by plus or minus 2.5 percent.
- Actual peak demand could vary upwards by 60 MW during extreme cold weather conditions and downward by 75 MW during mild weather.
- The average winter peak for 2014/15 could be 35 MW higher or lower than forecast.

This information will be taken into consideration in Hydro's winter peak demand forecasts and will be communicated to all forecast users.

4.4 Customer Coincidence

Customer class coincidence factors are used by Hydro in its monthly forecast to determine the contribution of each customer class's peak to the overall system peak. The customer class coincidence factors used in Hydro's monthly forecasts are based on historical data records maintained by Hydro and are provided in Appendix C. Hydro has reviewed these historical coincidence factors and has made the following observations:

- The coincidence factors for Newfoundland Power and Hydro Rural have increased since the decline of the island industrial load associated with paper mill and paper machine closures.
- Coincidence factors are expected to be affected by the forecasted increase in industrial load associated with nickel processing at Long Harbour.

Based on these observations Hydro has concluded that higher coincidence factors should apply to the utility demand forecasts for determining its forthcoming winter peak demand forecast and coincidence factors should be reviewed once industrial loads increase. It should be noted that the change in coincidence will increase the winter peak demand forecast by less than 10 MW.

5.0 LONG TERM PLANNING FORECAST

5.1 Sensitivity Analysis in Load Forecasting

A recommendation for Hydro's longer term load forecasting is the adoption of sensitivity analysis with respect to its baseline load forecasts. This practice would allow Hydro to better understand the generation and supply impacts associated with uncertain and differing load futures. In the past, Hydro had prepared alternative load forecast scenarios but had not regularly prepared formal sensitivity analysis of its load forecast. As well, Hydro's load forecasts were prepared on the basis of average historical weather conditions. Note that while the primary focus of the current review was with respect to winter peak demand forecasts, the recommendation to complete sensitivity analysis applies to both demand and energy forecasts.

In response to this recommendation to date, Hydro has reviewed the inputs of its long term load forecasting process and identified the following key variables for load forecast sensitivity analysis.

- Weather, including wind chill and heating degree days.
- Growth and saturation of electric heat market share.
- Growth in utility end use customers.
- Adoption rates of end-use energy efficient technologies.
- Large industrial load.

With respect to system peak demand supply planning, Hydro incorporated sensitivity analysis with its application for the new CT at Holyrood and considered the impact of P90 (90^{th} percentile) wind chill conditions on system peak demand. For all subsequent long term system planning analysis cycles, Hydro shall complete sensitivity analyses of the aforementioned variables and will consider the impact of P90 (90^{th} percentile) wind chill conditions for system peak demand planning purposes.

5.2 Share of Residential Electric Heat

Excluding the large load additions associated with nickel processing at Long Harbour, longer term load growth on the Island Interconnected System is sourced to growth of the Newfoundland Power customer base, whose load is highly influenced by the market share of electric heat within the residential customer class[3]. Hydro's load forecast models predict electric heat customers based on the penetration of electric heat in new residential customers as well as conversions to and from electric heat in existing residential customers.

Hydro has long understood that peak demand forecast accuracy for the Island Interconnected System is dependent on maintaining current information on the many factors impacting the market share of electric heat and understanding the impacts that electric heat has on its system peaks. Hydro maintains this information by:

- Collecting and maintaining databases of retail customers and electric heat penetration and conversion activity.
- Collecting and maintaining databases of retail energy prices.
- Monitoring of changes in space heating technologies.
- Customer surveys.
- Monitoring of other Canadian utilities.

The Ventyx review of Hydro's long term load forecasting model recommended that Hydro continue to refine its models with respect to predicting the penetration of electric heat and the conversions to electric heat. In addition, it recommended that Hydro further enhances its understanding of the impacts of electric heat on the system through continued surveying of the customer base in terms of both average use and saturation of this end use.

With respect to predicting the penetration of electric heat and the conversions to electric heat, Hydro has made minor improvements in its forecasting models for completion of its next long

[3] Except in extended periods of time with low fossil fuel prices, virtually all general service customer additions have electric heat based space heating systems installed as a primary heat source.

term planning analysis[4] and, as in the past, will seek additional improvements with each annual update of its models.

With respect to further enhancing its understanding of the impacts of electric heat on the system, Hydro will complete its review of Newfoundland Power's recent customer survey and determine the requirement for a future Hydro customer survey.

5.3 Review of Historical Peak Weather Conditions

Owing to the high market share of electric space heating within the utility end-use customer base, the Island Interconnected System peaks have generally occurred (in and around} the coldest winter days.

Hydro's long term peak demand forecast for the Newfoundland Power system relies on Hydro's historical record of Newfoundland Power's system peaks to define the appropriate peak demand weather conditions for long term planning purposes. As part of this review and given the increased market share of electric heat on the Island Interconnected System, Hydro has recalculated its peak demand weather condition based on the coldest winter weather condition for each of the last 30 years. Appendix D includes a table of these weather conditions. The following summarizes the impact of this refined data assumption:

- The 30- year average peak demand weather condition is calculated to be -27.5 °C and is approximately one degree colder than the previous planning assumption.
- The impact on Island Interconnected peak demand based on the recalculated average peak demand weather condition is less than 10 MW.

[4] As measured by the R^2 coefficient of determination.

6.0 SUMMARY

In response to recommendations from internal reports and recommendations from Ventyx, the Liberty Group and the Public Utilities following the January 2014 supply disruptions, Hydro undertook reviews of its short term hourly, monthly and long term planning forecasting methodologies and has made the following improvements.

Short term

- Implemented a new version of Nostradamus Software, added training parameters, modified training and verification periods and increased frequency of forecasting (currently only on the Development environment but shortly to be moved to the Production environment).
- Modified the short term load forecasting procedure to forecast only conforming loads in Nostradamus and add industrial load in a later step, and to allow adjustment for unusual losses or other system conditions.
- Developed a system of adjusting the short term load forecast if system losses are expected to be unusual because of generation dispatch.

Medium term

- The winter peak demand forecast will now communicate information from sensitivity analyses that includes expected peak demand ranges at average weather conditions and predicted peak demands associated with colder than normal weather conditions.
- Baseline transmission loss forecasts will now reflect current and any planned changes to system configurations.
- The medium term operating load forecast prepared in the fall will now provide System Operations with a winter peak demand forecast on a total Island system basis.

Long term

- Hydro will use the re-calibrated historical wind chill values for forecasting system peak demands.
- Hydro will continue to research and refine its understanding of the system impacts of electric space heating.
- Sensitivity analysis of longer term load to key variables will be assessed at each planning cycle including an assessment of P90 (90^{th} percentile) wind chill for peak load.

The effects of all of these improvements will be monitored through the winter of 2014/15 and reviewed in the spring to ensure that the expected improvements in accuracy have been achieved.

APPENDIX A

NEW HYDRO LOAD FORECASTING MODEL DEFINITIONS

Ongoing reviews of Newfoundland and Labrador Hydro System Operations following the supply disruptions in January 2014 have identified an opportunity for improvement in the way that the load forecasts are discussed and presented. Hydro will no longer distinguish between System generation and Island generation (including Newfoundland Power and Corner Brook Pulp and Paper load and generation) – all native load, irrespective of which entity meets the load, will be included in all future forecasts.

Nostradamus will forecast **Utility Load** then (outside Nostradamus) Hydro will

- Estimate **Industrial Load** based on historic use and forecasts provided by industrial customers
- add forecasted **Utility Load** from Nostradamus to get
- **Total Load Forecast**

In presentation of the load forecast, Hydro will no longer make any adjustments to the Total Load forecast to add or subtract expected wind or other nonutility generation. Hydro is responsible for meeting the **Total Load** and will meet it using all resources under its control, including non-utility generators and available wind. Changes are being made in the Automatic Generation Control (AGC) and Energy Management System processes and procedures to facilitate this manner of operating and reporting.

AVALON LOAD MODEL:

Total Avalon Load is the sum of:

- Hardwoods generation
- Western Avalon TL203 and TL237
- Newfoundland Power Generation on Avalon
- Holyrood generation
- Fermeuse Wind

Industrial Avalon Load is

- Vale and Praxair on TL208

Avalon Utility Load is **Total Avalon Load** minus **Industrial Avalon Load.** Nostradamus will forecast **Avalon Utility Load.**

Hydro will add an estimate of **Industrial Load** at Vale and Praxair, based on customer forecasts and operating information, to the Nostradamus estimate of **Avalon Utility Load** to get the **Total Avalon Load Forecast**.

This change in the way the Avalon forecast is presented will necessitate a change in the way the Holyrood unit commitment thresholds are defined. In the past, only Hydro generation and load was considered, now the thresholds are required to include the generation from Newfoundland Power and the Fermeuse wind farm in order for them to be meaningfully compared with the Avalon load forecast.

ISLAND LOAD MODEL:

Total Island Load is the sum of:

- Hydro gen including hydro and thermal including Exploits, wind, Corner Brook Pulp and Paper Cogeneration
- Total NP generation
- Deer Lake Power Generation

Industrial Island is

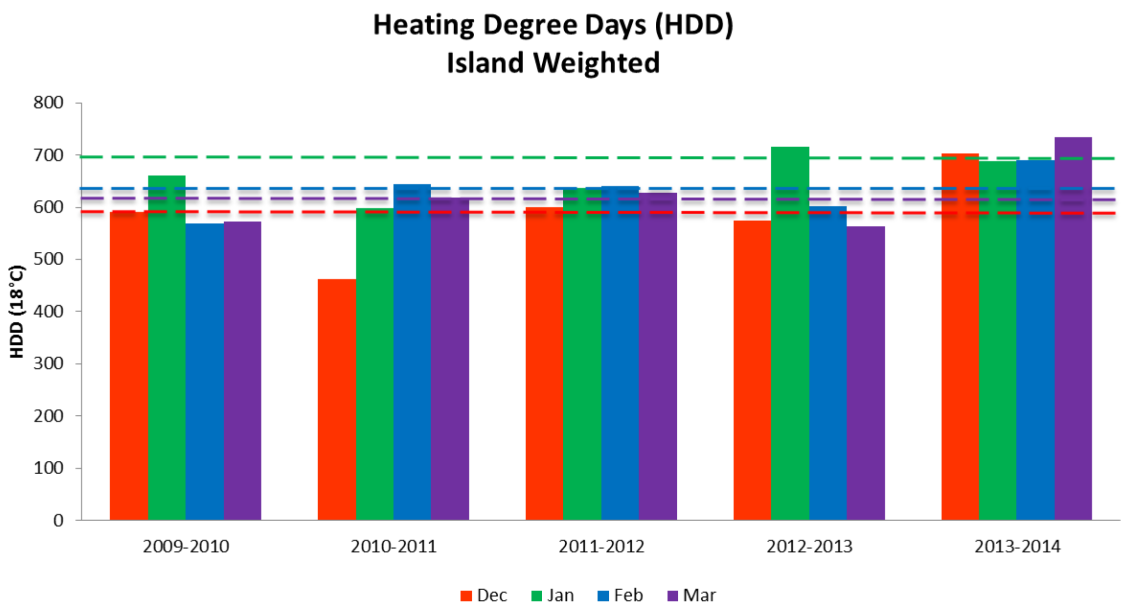
- Vale and Praxair on TL208
- Corner Brook Pulp and Paper at Massey Drive and Deer Lake
- North Atlantic Refinery at Come-by-chance T1 and T2
- Aur Resources at Buchans

Island Utility Load is **Total Island Load** minus **Industrial Island Load.** Nostradamus will forecast **Island Utility Load.**

The estimated **Industrial Island Load** will be added to the Nostradamus estimate of **Island Utility Load** to get the **Total Island Load Forecast**. The **Industrial Island Load forecast** will be based on forecasts and other operating information provided by the industrial customers and observation of recent use.

APPENDIX B

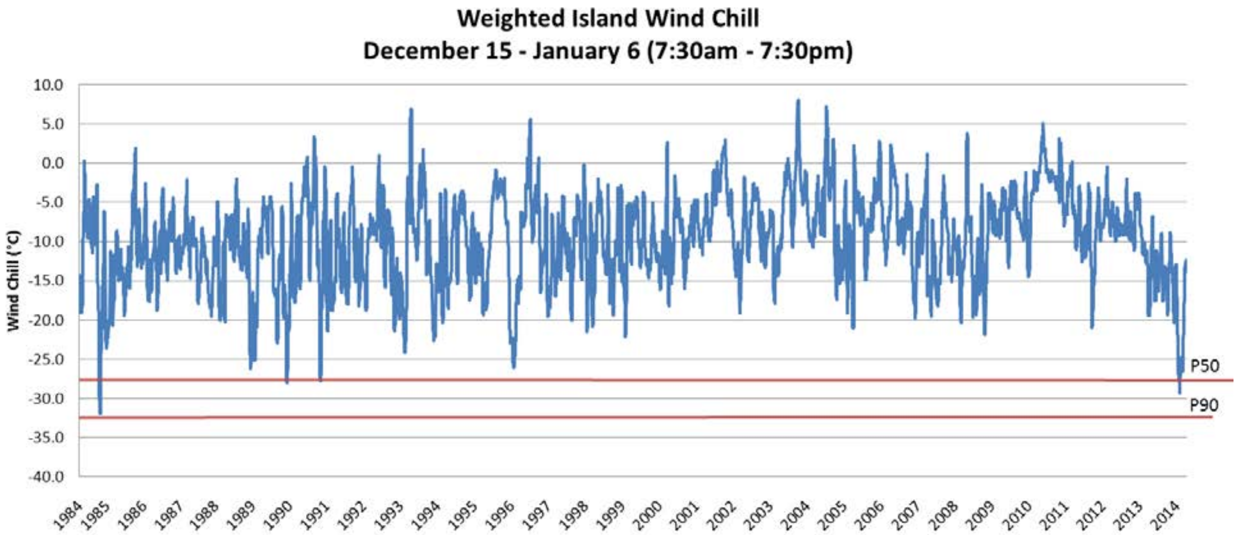
Comparison of 2014 Weather Conditions to Historical Weather

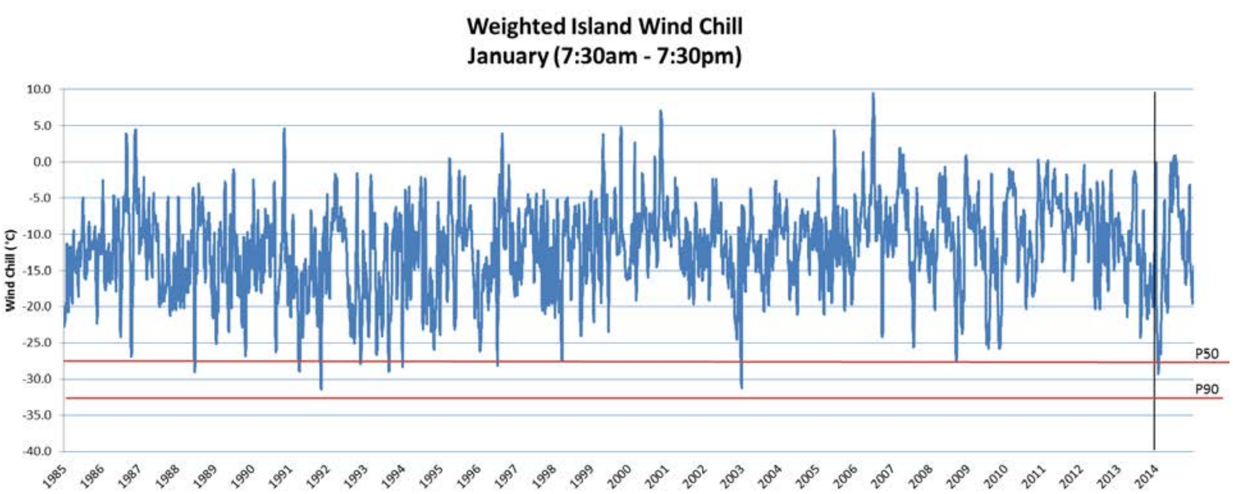


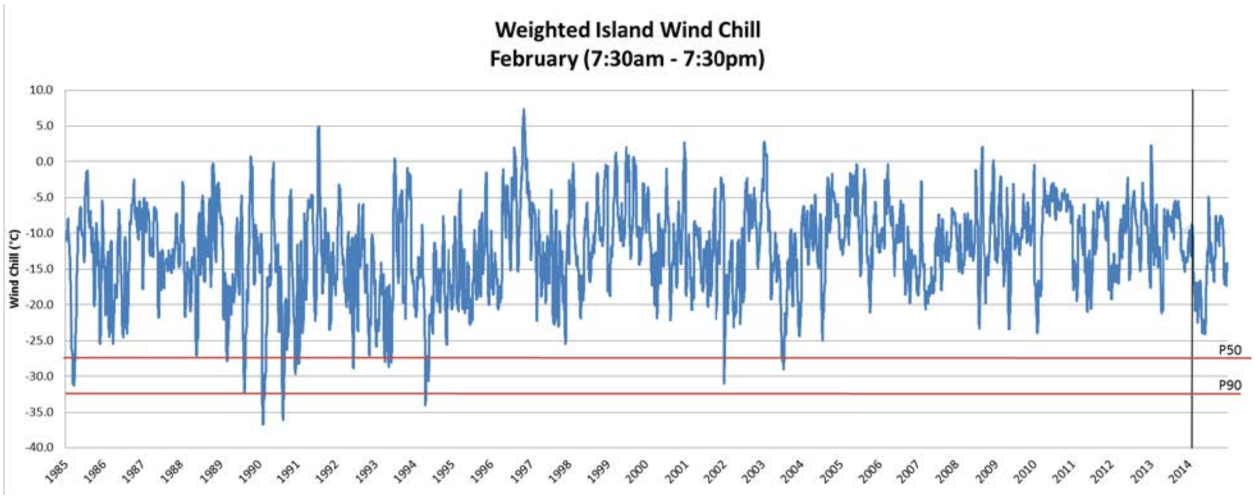
Notes:
Heating degree-days for a given day are the number of degrees Celsius that the mean temperature is below 18°C. If the temperature is equal to or greater than 18°C, then the number will be zero.
30 year HDD normals are from 1981 to 2010.

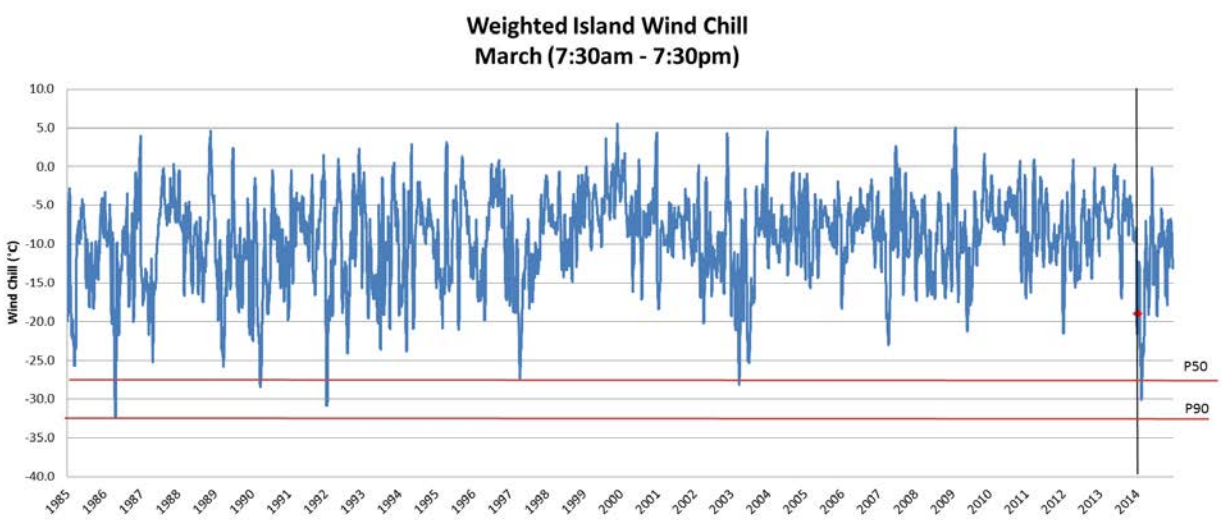
Heating Degree Days - Island Weighted
1981 to 2010 Normals

Jan	Feb	Mar	Dec
716	662	648	617


Weighted Island Wind Chill
December 15 - January 6 (7:30am - 7:30pm)
Wind Chill (°C)
10.0
5.0
0.0
-5.0
-10.0
-15.0
-20.0
-25.0
-30.0
-35.0
-40.0
P50
P90
1984 1985 1986 1987 1988 1989 1990 1991 1992 1993 1994 1995 1996 1997 1998 1999 2000 2001 2002 2003 2004 2005 2006 2007 2008 2009 2010 2011 2012 2013 2014


Weighted Island Wind Chill
January (7:30am - 7:30pm)
Wind Chill (°C)
10.0
5.0
0.0
-5.0
-10.0
-15.0
-20.0
-25.0
-30.0
-35.0
-40.0
P50
P90
1985 1986 1987 1988 1989 1990 1991 1992 1993 1994 1995 1996 1997 1998 1999 2000 2001 2002 2003 2004 2005 2006 2007 2008 2009 2010 2011 2012 2013 2014


Weighted Island Wind Chill
February (7:30am - 7:30pm)
Wind Chill (°C)
P50
P90


Weighted Island Wind Chill
March (7:30am - 7:30pm)
Wind Chill (°C)
P50
P90

APPENDIX C

Customer Coincidence Factors

Customer Coincidence Factors (C.F.) for Island Interconnected System Annual Peak

			Newfoundland Power			Hydro Rural			Industrial		
Year	DD-MM	Time	NCP	COP	C.F.	NCP	COP	C.F.	NCP	COP	C.F.
1999	8-Jan	17:00	1,010	958	94.9%	85	73	86.3%	200	192	96.0%
2000	10-Dec	12:00	1,025	979	95.5%	83	72	87.3%	202	186	92.0%
2001	13-Dec	18:00	989	942	95.3%	74	68	91.5%	202	200	98.8%
2002	31-Jan	21:00	1,176	1,130	96.1%	82	77	93.5%	208	188	90.3%
2003	15-Feb	18:00	1118	1,118	100.0%	81	79	97.0%	208	190	91.6%
2004	6-Dec	17:00	1167	1,163	99.6%	87	82	94.1%	213	156	72.9%
2005	6-Jan	18:00	1,124	1,122	99.8%	80	77	96.5%	211	192	91.1%
2006	30-Dec	18:00	1,142	1,106	96.8%	81	76	93.4%	207	194	93.7%
2007	18-Jan	17:00	1,136	1,112	97.9%	80	71	88.9%	205	191	93.2%
2008	21-Dec	18:00	1,181	1,134	96.0%	89	80	90.2%	194	171	88.2%
2009	27-Jan	08:00	1,219	1,218	100.0%	88	76	86.7%	198	176	89.0%
2010	2-Feb	18:00	1,206	1,195	99.1%	82	82	100.0%	187	149	79.4%
2011	25-Dec	10:00	1,229	1,229	100.0%	96	90	94.6%	184	178	96.7%
2012	16-Jan	18:00	1,241	1,241	100.0%	89	88	98.5%	184	169	91.6%
2013	14-Dec	18:00	1,336	1,336	100.0%	96	94	98.4%	170	144	84.4%

Notes:

1. NCP - Non-coincident Peak MW
2. COP - Coincident Peak MW

APPENDIX D

Historical Winter Wind Chill Values

Historical Winter Wind Chill Values for the Island Interconnected System

Winter of:	Year of Occurance:	Month	Day	Period Ending:	Weighted Island Wind Chill (^{o}C Equivalent)
1984	1984	December	27	17:30	-31.9
1985	1986	March	10	19:30	-32.3
1986	1986	December	9	10:30	-29.8
1987	1988	January	15	15:30	-29.0
1988	1989	February	18	8:30	-32.3
1989	1990	February	3	17:30	-36.8
1990	1991	January	26	15:30	-31.4
1991	1992	March	2	13:30	-30.8
1992	1993	January	20	14:30	-29.0
1993	1994	February	9	7:30	-34.0
1994	1995	January	12	15:30	-23.2
1995	1996	January	16	19:30	-28.1
1996	1997	March	9	19:30	-27.3
1997	1998	January	7	18:30	-27.4
1998	1999	January	15	7:30	-23.4
1999	2000	February	18	19:30	-22.1
2000	2001	February	23	7:30	-21.9
2001	2002	January	31	19:30	-31.2
2002	2003	February	16	7:30	-29.0
2003	2004	February	16	19:30	-25.0
2004	2005	February	22	8:30	-21.1
2005	2006	January	23	14:30	-24.1
2006	2007	January	18	12:30	-25.6
2007	2008	January	22	14:30	-27.5
2008	2009	January	27	10:30	-25.8
2009	2010	February	3	7:30	-23.9
2010	2011	February	11	18:30	-21.0
2011	2012	March	1	15:30	-21.5
2012	2013	January	19	8:30	-24.2
2013	2014	March	5	9:30	-30.0

P-50	-27.5
P-75	-30.6
P-90	-32.3

Notes:
1. Regional wind chills calculated from average 20 hour temperature and average 8 hour wind speed ending between the hours of 7:30 AM and 7:30 PM.
2. Weighted Island wind chill calculated using 2013 year end Newfoundland Power regional energy sales as weights.