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February 15, 2016

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

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

Dear Ms. Blundon:

Re: Newfoundland and Labrador Hydro - the Board's Investigation and Hearing into Supply Issues and Power Outages on the Island Interconnected System – Nostradamus Upgrades Monthly Report

In accordance with item 2.1 of the Liberty Report Recommendations dated December 17, 2014, wherein Hydro is required to "provide the Board with monthly updates on the status of Nostradamus upgrades until the production model is fully in-service and shaken down", please find enclosed the original plus 12 copies of Hydro's report entitled *Accuracy of Nostradamus Load Forecasting at Newfoundland and Labrador Hydro Monthly Report: January 16, 2016.*

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

Yours truly,

NEWFOUNDLAND AND LABRADOR HYDRO

Jennifer M. Williams, P. Eng
Manager, Regulatory Engineering

JMW/bs

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

ecc: Roberta Frampton Benefiel – Grand Riverkeeper Labrador

Accuracy of Nostradamus Load Forecasting at Newfoundland and Labrador Hydro

Monthly Report: January 2016

Newfoundland and Labrador Hydro

February 15, 2016

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1 NOSTRADAMUS LOAD FORECASTING

1.1 Nostradamus

Newfoundland and Labrador Hydro (Hydro) uses software called Nostradamus, by Ventyx, for short-term load forecasting with a time frame of seven days. "The Nostradamus Neural Network Forecasting system is a flexible neural network based forecasting tool developed specifically for utility demand forecasting. Unlike conventional computing processes, which are programmed, neural networks use sophisticated mathematical techniques to train a network of inputs and outputs. Neural networks recognize and learn the joint relationships (linear or non-linear) between the ranges of variables considered. Once the network learns these intricate relationships, this knowledge can then easily be extended to produce accurate forecasts." (Nostradamus User Guide, Release 8.2, Ventyx, an ABB Company, May 2014).

The Nostradamus model is trained using a sequence of continuous historic periods of hourly weather and demand data, then forecasts system demand using predictions of those same weather parameters for the next seven days.

1.2 Short-Term Load Forecasting

Hydro uses its short-term load forecast to manage the power system and ensure adequate generating resources are available to meet customer demand.

1.2.1 Utility Load

Hydro contracts Amec Foster Wheeler (Amec) to provide the weather parameters in the form of twice daily hourly weather forecasts for a seven-day period. At the same time as the weather forecast data are provided, Amec also provides recent observed data at the same locations. The forecast and actual data are automatically retrieved from Amec and input to the Nostradamus database.

Nostradamus can use a variety of weather parameters for forecasting as long as a historical record is available for training. Hydro currently uses: air temperature, wind speed, and cloud cover. Nostradamus can use each variable more than once, for example both the current and forecast air temperatures are used in forecasting load. Wind chill is not used explicitly as the neural network function of Nostradamus will form its own relationships between load, wind and temperature, which should be superior to the one formula used by Environment Canada to derive wind chill.

Weather data for four locations are used in Nostradamus: St. John's, Gander, Deer Lake, and Port aux Basques. Data from April 1, 2012 to March 31, 2015 are being used for training and verification purposes. The training and verification periods are selected to provide a sufficiently long period to ensure that a range of weather parameters are included, e.g., high and low temperatures, but short enough that the historic load is still representative of loads that can be expected in the future. Preliminary training has been done on the Development system using data up to September 2015, but that has not been moved to Production yet.

In addition to the weather and demand data, a parameter that indicates daylight hours each day is input to Nostradamus.

Demand data for the Avalon Peninsula alone and for the Island Interconnected System as a whole are input to Nostradamus automatically each hour. Only total utility load (conforming), Newfoundland Power's and Hydro's, is input in the Nostradamus model. Industrial load (non-conforming), which is not a function of weather, is forecast outside the Nostradamus program and added to the forecasts from Nostradamus to derive the total load forecast.

During the process of training the Nostradamus model, it creates separate submodels for weekdays, weekends and holidays to account for the variation in customer use of electricity. Nostradamus has separate holiday groups for statutory holidays and also for days that are known to have unusual loads, for instance the days between Christmas and New Year's and the school Easter break.

1.2.2 Industrial Load

Industrial load tends to be almost constant, as industrial processes are independent of weather. Under the current procedure, the power-on-order for each Industrial Customer, and the expected owned generation from Corner Brook Pulp and Paper (CBPP), are used for the industrial load forecast unless System Operations engineers modify the forecast based on some knowledge of customer loads, for instance a decrease due to planned reduced production at CBPP or a ramp up in the load expected at Vale. Engineers can change the expected load in one or more cells of a seven day by twenty-four hour grid, or can change the default value to be used indefinitely.

1.2.3 Supply and Demand Status Reporting

The forecast peak reported to the Board of Commissioners of Public Utilities (the Board) on the daily Supply and Demand Status Report is the forecast peak as of 7:20 am. The weather forecast for the next seven days and the observed weather data for the previous period are input at approximately 5:00 am and again at mid-day (1:00 pm or 2:00 pm depending on Daylight Saving Time). Nostradamus is run every hour of the day and the most recent load forecast is available for reference by System Operations engineers and the Energy Control Centre operators for monitoring and managing available spinning reserves. The within day load forecast updates are used by operators to decide if additional spinning reserve is required in advance of forecast system peaks.

1.3 Load Forecasting Improvements

Hydro has implemented the following changes to the load forecasting process since January 2014:

- Additional training for staff;
- Revised training and verification periods and additional quality control of the weather data, including the data from January 2014 which will improve the capability of the model to forecast loads at low temperatures;

- Adding weather parameters for cloud cover and daylight hours;
- Modifying actual demand data used in Nostradamus training to remove unusual system conditions such as significant outages;
- Changing forecasting processes so that Nostradamus forecasts only utility load, with industrial forecasts done separately;
- Changing forecasting process to allow adjustments to the generated forecast to account for unusual system conditions (e.g., to account for an abnormal system configuration that may result in more or less system losses); and
- Creation of new plots and tables showing the load forecast, spinning reserve, and available reserve, which are available on demand to System Operations staff for managing the system;
- Requirement for regular weather forecast accuracy reviewing and reporting from Amec; and
- Move to two weather forecasts per day and an update of observed weather data midday.
- Version 8.2.4 of the Nostradamus software was installed on Production in mid-August 2015. Implementation of the new version had no noticeable effect on the forecasts.

1.4 Potential Sources of Variance

Improvements made to the Nostradamus forecasting model and Hydro's processes for load forecasting have improved the reliability of the load forecasts. As with any forecasting, however, there will be ongoing discrepancies between the forecast and the actual values. Typical sources of variance in the load forecasting are as follows:

- Differences in the industrial load forecast due to unexpected changes in customer loads;
- Inaccuracies in the weather forecast, particularly temperature, wind speed or cloud cover; and
- Non-uniform customer behaviour which results in unpredictability.

2 JANUARY 2016 FORECAST ACCURACY

2.1 Description

Table 1 presents the daily forecast peak, the observed peak, and the available system capacity, as included in Hydro's daily Supply and Demand Status Reports submitted to the Board for each day in January 2016. The data are also presented in Figure 1. The actual peaks, as reported to the Board, varied from 1259 MW on January 27 to 1617 MW on January 5. January 5 was the only day in January when the peak was above 1600 MW, which would be considered a high demand, and it was forecast within 1.4% error.

The available capacity during the month was between 1780 MW on January 10 and 2045 MW on January 3. Reserves were sufficient throughout the period.

Table 2 presents error statistics for the peak forecasts during the month of January 2016. Figure 2 is a plot of the forecast and actual peaks, as shown in Figure 1, but with the addition of a bar chart showing the difference between the two data series. In both the tables and the figures, a positive error is an overestimate; a negative error is an underestimate.

Through the month of January the forecast peak was in a range between 3.0% below the actual peak and 5.1% above the actual peak. On the best day the forecast peak was the same as the actual peak; on the worst day it was 73 MW too high. On average, the forecast peak was 29 MW different than the actual peak, or 2.0% of actual.

In the review of forecast accuracy statistics for January 2016 in Table 2, Hydro offers further detail on the difference found between forecast and actual peaks for January 12 and 25. In addition, forecasts between these two dates were reviewed. The period showed an unusual pattern of all peaks being over forecast; errors are more typically random.

2.2 Data Adjustment

On January 6 and again on January 8, Hydro requested that Newfoundland Power curtail load to reduce both the morning and afternoon peaks by approximately 10 MW. Therefore, System Operations adjusted the Avalon and Island utility load values input to Nostradamus upwards by 10 MW to represent what the load would have been without curtailments. These adjustments were made to the Nostradamus data so that in the future, when January 2016 data are used in training the forecasting model, Nostradamus will use a value that is not affected by the curtailments.

Table 1 January 2016 Load Forecasting Data

Date	Forecast Peak, MW	Actual Peak, MW	Available Island Supply, MW	Forecast Reserve, MW
1-Jan-16	1415	1395	1995	677
2-Jan-16	1375	1395	2015	736
3-Jan-16	1415	1401	2045	727
4-Jan-16	1470	1455	2030	657
5-Jan-16	1595	1617	2000	504
6-Jan-16	1525	1518	1855	428
7-Jan-16	1425	1417	1795	467
8-Jan-16	1545	1529	1830	383
9-Jan-16	1445	1489	1945	597
10-Jan-16	1425	1425	1780	452
11-Jan-16	1455	1477	1790	432
12-Jan-16	1460	1394	1845	482
13-Jan-16	1485	1472	1800	412
14-Jan-16	1495	1458	1795	397
15-Jan-16	1500	1477	1820	418
16-Jan-16	1450	1413	2020	667
17-Jan-16	1440	1428	2000	657
18-Jan-16	1450	1404	1985	632
19-Jan-16	1480	1426	1985	602
20-Jan-16	1475	1441	1850	472
21-Jan-16	1485	1440	1840	452
22-Jan-16	1500	1452	1805	403
23-Jan-16	1480	1432	1805	422
24-Jan-16	1465	1438	1815	447
25-Jan-16	1515	1442	1800	383
26-Jan-16	1550	1546	1820	368
27-Jan-16	1230	1259	1815	679
28-Jan-16	1430	1393	1835	502
29-Jan-16	1400	1420	1820	516
30-Jan-16	1485	1469	1810	422
31-Jan-16	1455	1448	1795	437
Minimum	1230	1259	1780	368
Average	1462	1444	1875	511
Maximum	1595	1617	2045	736

Notes:
Forecast peak, available capacity and forecast reserve are rounded to the nearest 5 MW.
Forecast peak and available capacity presented is as reported to the Board. The forecast is updated hourly throughout the day for use in maintaining adequate generation reserves.
Forecast Reserve = Available Island Supply - (Forecast Peak - CBPP Interruptible Load (when applicable) - the impact of voltage reduction).

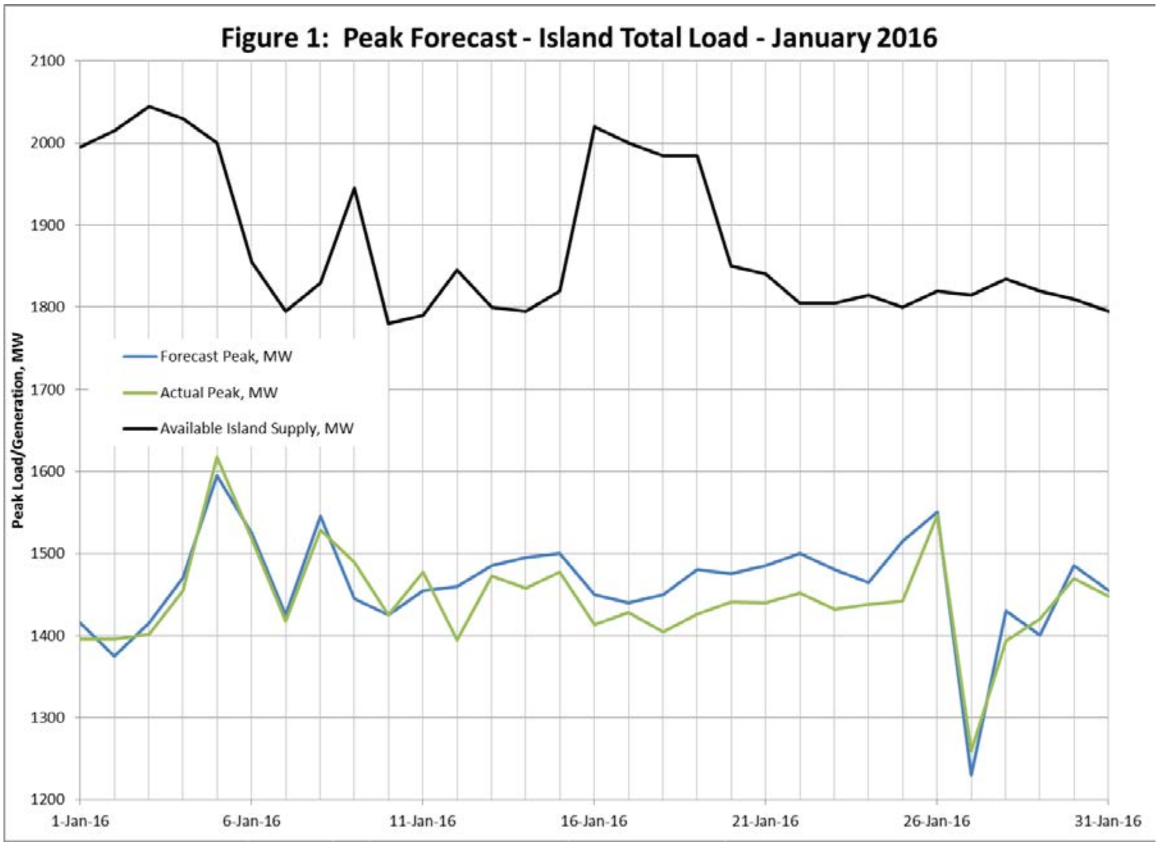
Figure 1: Peak Forecast - Island Total Load - January 2016
Peak Load/Generation, MW
2100
2000
1900
1800
1700
1600
1500
1400
1300
1200
1-Jan-16
6-Jan-16
11-Jan-16
16-Jan-16
21-Jan-16
26-Jan-16
31-Jan-16
Forecast Peak, MW
Actual Peak, MW
Available Island Supply, MW

Table 2 January 2016 Analysis of Forecast Error

Date	Actual Peak, MW	Forecast Peak, MW	Error, MW	Absolute Error, MW	Percent Error	Absolute Percent Error	Actual/ Forecast
1-Jan-16	1395	1415	20	20	1.4%	1.4%	1.4%
2-Jan-16	1395	1375	-20	20	-1.4%	1.4%	-1.5%
3-Jan-16	1401	1415	14	14	1.0%	1.0%	1.0%
4-Jan-16	1455	1470	15	15	1.0%	1.0%	1.0%
5-Jan-16	1617	1595	-22	22	-1.4%	1.4%	-1.4%
6-Jan-16	1518	1525	7	7	0.5%	0.5%	0.5%
7-Jan-16	1417	1425	8	8	0.6%	0.6%	0.6%
8-Jan-16	1529	1545	16	16	1.0%	1.0%	1.0%
9-Jan-16	1489	1445	-44	44	-3.0%	3.0%	-3.0%
10-Jan-16	1425	1425	0	0	0.0%	0.0%	0.0%
11-Jan-16	1477	1455	-22	22	-1.5%	1.5%	-1.5%
12-Jan-16	1394	1460	66	66	4.7%	4.7%	4.5%
13-Jan-16	1472	1485	13	13	0.9%	0.9%	0.9%
14-Jan-16	1458	1495	37	37	2.5%	2.5%	2.5%
15-Jan-16	1477	1500	23	23	1.6%	1.6%	1.5%
16-Jan-16	1413	1450	37	37	2.6%	2.6%	2.6%
17-Jan-16	1428	1440	12	12	0.8%	0.8%	0.8%
18-Jan-16	1404	1450	46	46	3.3%	3.3%	3.2%
19-Jan-16	1426	1480	54	54	3.8%	3.8%	3.6%
20-Jan-16	1441	1475	34	34	2.4%	2.4%	2.3%
21-Jan-16	1440	1485	45	45	3.1%	3.1%	3.0%
22-Jan-16	1452	1500	48	48	3.3%	3.3%	3.2%
23-Jan-16	1432	1480	48	48	3.4%	3.4%	3.2%
24-Jan-16	1438	1465	27	27	1.9%	1.9%	1.8%
25-Jan-16	1442	1515	73	73	5.1%	5.1%	4.8%
26-Jan-16	1546	1550	4	4	0.3%	0.3%	0.3%
27-Jan-16	1259	1230	-29	29	-2.3%	2.3%	-2.4%
28-Jan-16	1393	1430	37	37	2.7%	2.7%	2.6%
29-Jan-16	1420	1400	-20	20	-1.4%	1.4%	-1.4%
30-Jan-16	1469	1485	16	16	1.1%	1.1%	1.1%
31-Jan-16	1448	1455	7	7	0.5%	0.5%	0.5%
Minimum	1259	1230	-44	0	-3.0%	0.0%	-3.0%
Average	1444	1462	18	29	1.3%	2.0%	1.2%
Maximum	1617	1595	73	73	5.1%	5.1%	4.8%

Notes:
Forecast peak is rounded to the nearest 5 MW
Forecast peak presented is as reported to the Board. The forecast is updated hourly throughout the day for use in maintaining adequate generation reserves.

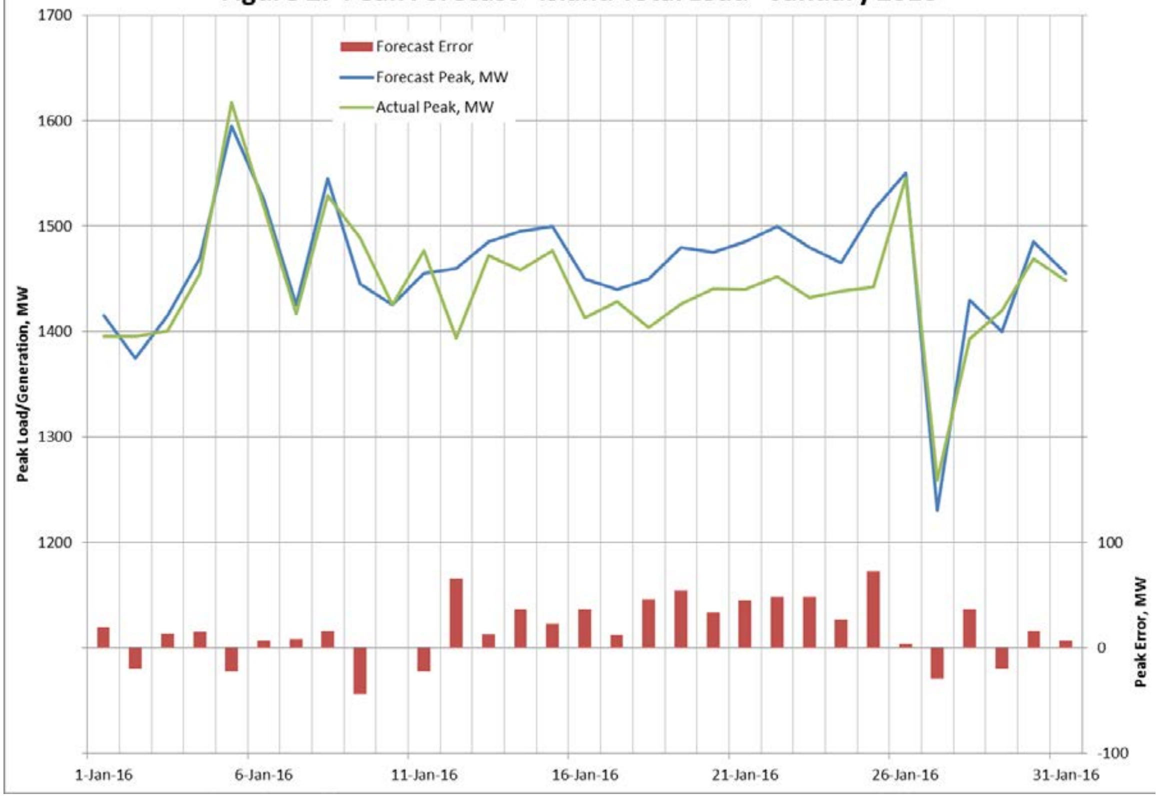

Figure 2: Peak Forecast - Island Total Load - January 2016

2.3 January 12, 2016

On January 12, the forecast peak at 7:20 am, as reported to the Board, was 1460 MW; the actual reported peak was 1394 MW. The absolute difference was 66 MW, 4.7% of the actual. Figure 3 includes an hourly plot of the load forecast for January 12 as well as several charts which examine components of the load forecast to assist in determining the sources of the differences between actual and forecast loads.

Figure 3(a) shows the hourly distribution of the load forecast compared to the actual load. The shape of the actual load was similar to forecast but was generally higher in the morning and lower after mid-afternoon. The forecast predicted a 5:00 pm peak of 1458 MW. The actual hourly peak was 1394 MW at 5:00 pm.

Figure 3(b) shows the hourly distribution of the utility load forecast only, i.e., the load forecast with the industrial component removed. The forecast utility peak of 1295 MW was closer to the actual utility peak of 1248 MW so a discrepancy in the industrial forecast contributed to the variance in the peak. The Kruger load at the time of the peak was only 94 MW, down from the power-on-order of 107 MW.

Figure 3(c) shows the actual temperature in St. John's compared to the forecast. Although Nostradamus uses weather data at four sites, the weather in St. John's tends to have the largest effect because of the concentration of population in St. John's. The actual temperature was 1 to 2 degrees higher than forecast for most of the day which would have resulted in a lower than anticipated load, so the error in the temperature forecast likely contributed to the overestimate in the load forecast.

Figure 3(d) shows the actual cloud cover in St. John's compared to the forecast. For most of the day the weather was cloudier than forecast. This would have resulted in a higher load than forecast so did not contribute to the overestimate error.

Figure 3(e) shows the actual wind speed in St. John's compared to the forecast. The wind speed was somewhat lower than forecast in the early part of the day but was accurate near the time of the peak so the error in the wind speed forecast probably did not contribute to the load forecast error.

The discrepancy between actual and forecast load for January 12 was likely a result of errors in both the industrial load and temperature forecasts. By later in the day, the forecast had improved and was within 2% of the actual. The hourly, within day, updates are used by Energy Control Centre operators to manage spinning reserve.

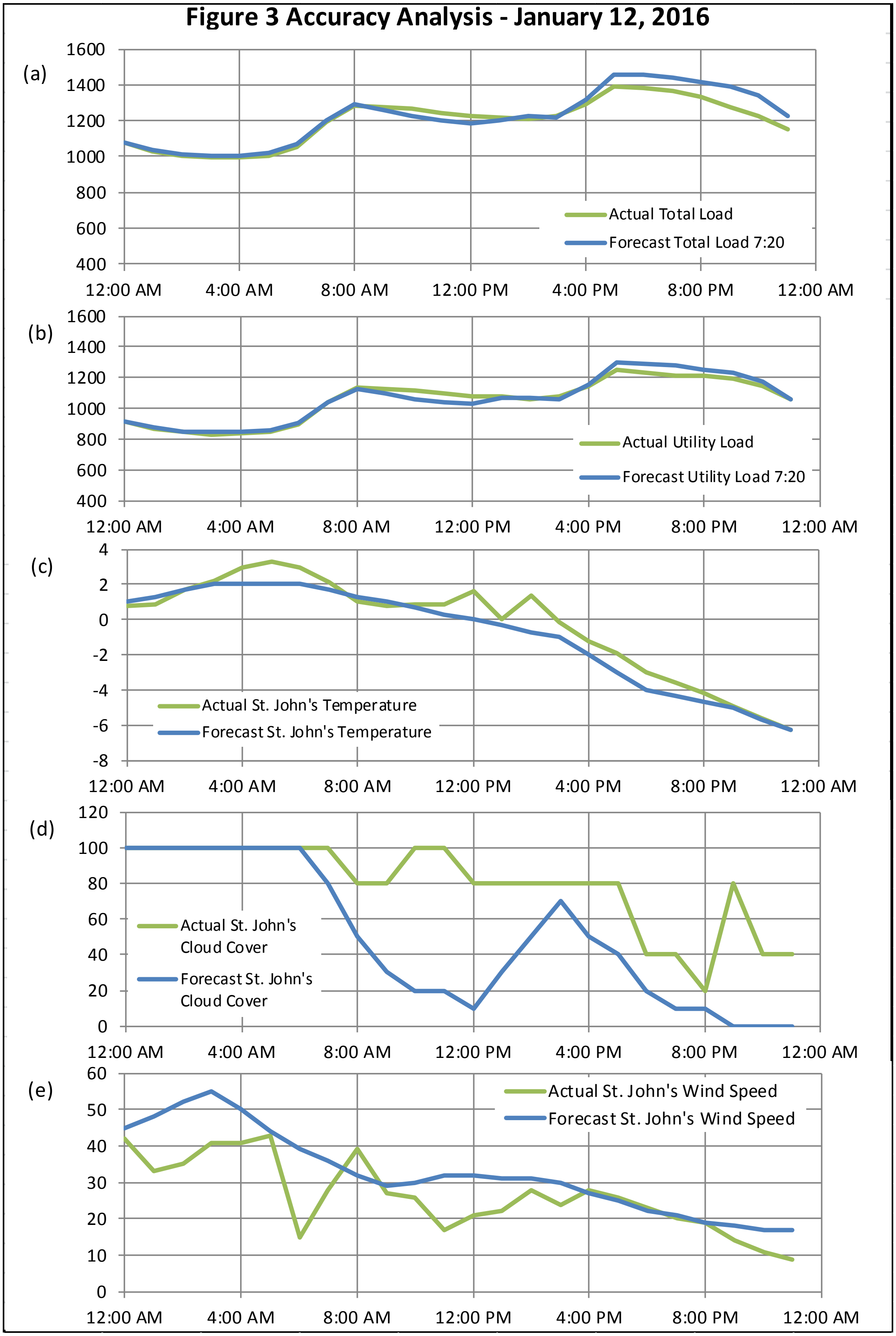
Figure 3 Accuracy Analysis - January 12, 2016
(a)
Actual Total Load
Forecast Total Load 7:20
(b)
Actual Utility Load
Forecast Utility Load 7:20
(c)
Actual St. John's Temperature
Forecast St. John's Temperature
(d)
Actual St. John's Cloud Cover
Forecast St. John's Cloud Cover
(e)
Actual St. John's Wind Speed
Forecast St. John's Wind Speed
12:00 AM
4:00 AM
8:00 AM
12:00 PM
4:00 PM
8:00 PM
12:00 AM

2.4 January 25, 2016

On January 25, the forecast peak at 7:20 am was 1515 MW; the actual reported peak was 1442 MW. The absolute difference was 73 MW, 5.1% of the actual. Figure 4 includes an hourly plot of the load forecast for January 25 as well as several charts which examine components of the load forecast to assist in determining the sources of the differences between actual and forecast loads.

Figure 4(a) shows the hourly distribution of the load forecast compared to the actual load. The 7:20 am forecast predicted a 7:00 pm peak of 1514 MW. The actual peak as input to Nostradamus was 1439 MW at 8:00 am (1442 MW was at 8:15 am). The forecast was accurate for the time of the actual peak but predicted a higher peak later in the day that did not transpire.

Figure 4(b) shows the hourly distribution of the utility load forecast only, i.e., the load forecast with the industrial component removed. It shows that the error in the utility forecast was somewhat less than the error in the total forecast, so error in the industrial forecast may have contributed to the error in the total load forecast but there were clearly other contributors also.

Figures 4(c) through 4(e) show comparisons of the weather conditions to the weather forecasts. Figure 4(c) shows the actual temperature in St. John's compared to the forecast. Although Nostradamus uses weather data at four sites, the weather in St. John's tends to have the largest effect because of the concentration of population in St. John's. The temperature forecast was generally quite good, with a maximum error of one to two degrees in the late afternoon. The temperature forecast may have contributed somewhat to the over forecast.

Figure 4(d) shows the actual cloud cover in St. John's compared to the forecast. The forecast underestimated the cloud cover which would have led to a higher rather than a lower load so the error in the cloud cover did not contribute to the error in the forecast.

Figure 4 Accuracy Analysis - January 25, 2016

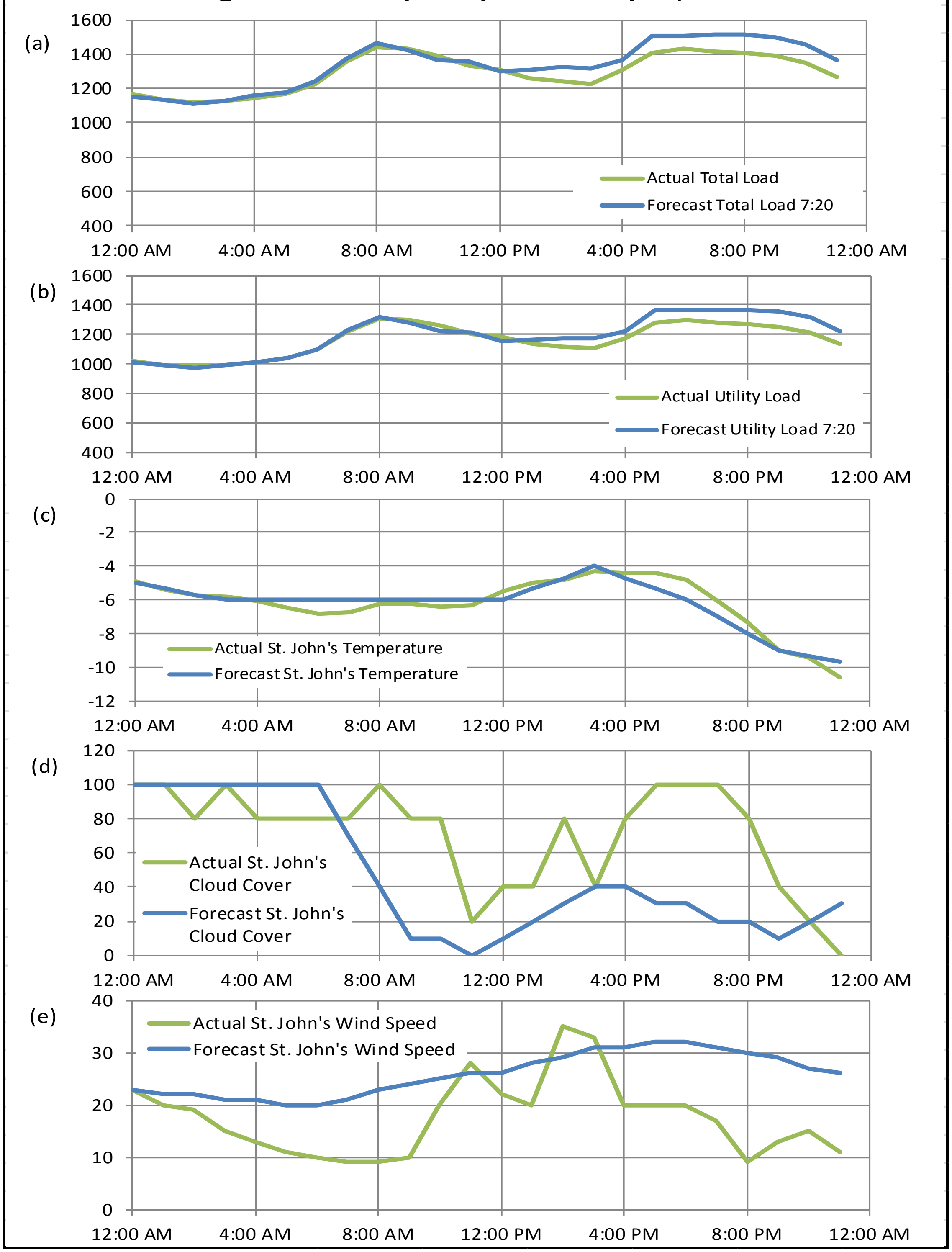

Figure 4(e) shows the actual wind speed in St. John's compared to the forecast. For almost all of the day the actual wind speed was significantly lower than forecast so the error in the wind speed forecast likely contributed to the load forecast error.

The discrepancy between actual and forecast load for January 25 was likely a result of error in the industrial forecast and the wind forecast. By early afternoon, the forecast had improved and was within 2% of the actual. The hourly, within day, updates are used by Energy Control Centre operators to manage spinning reserve.

2.5 January 12 to 25, 2016

In January 2016 the peak in the total Island load was overestimated on 24 days and underestimated on six days; on one day the forecast and actual peaks matched perfectly. With random errors, it would be expected that number of over and underestimates would be equal. Furthermore, there was an approximately two week period when the peak was overestimated every day, by an average of approximately 3%. Data for this period was reviewed to ascertain whether there was some systemic bias to the forecasts.

Calculations of the actual forecasts and the data feeds into Nostradamus were checked and no errors were found. Nothing particularly unusual was noted to be occurring on the system during that period that might explain a lower than forecast load.

Figure 5 shows the forecast and actual peaks for three load forecasts for the two week period from January 12 to January 25:

- the total Island load – average error 40 MW or 2.8%
- the Island utility forecast – average error 26 MW or 2.1%
- the Avalon utility forecast – average error 14 MW or 1.9%

The duration of consistent overestimates is shorter for the utility forecasts than for the total forecast and shorter still for the Avalon utility forecast.

The fact that the utility load was forecast more accurately than the total load indicates that at least some of the overstimate was a result of the industrial load forecasts. During the full period in question the Vale load was lower than forecast and for days within the period the Kruger load was also below forecast.

Of the two utility forecasts, the Avalon load was marginally better forecast than the Island load, but both were still consistantly over forecast.

Figures 6 through 9 show comparisons of daily temperature and wind forecasts and actual data for St. John's. No weather related explanation for the load forecast error is obvious. For a portion of the duration of interest the temperature was consistently over forecast, but during heating season that would lead to an underestimate rather than an overestimate of load. For most of the period the average wind speed was overestimated which could have contributed to an over forecast, but in fact that trend was observable through most of the month, even when the load forecast was more accurate.

In conclusion, no complete explanation has been found for the consistent overestimate of the load. Errors in the industrial forecasts contributed, but the utilty forecast showed much the same trend. Given that the magnitude of the error was not high, System Operations will just continue to monitor the forecast. If this trend continues into other months, addional investigations will be undertaken. If the phenomena reoccurs, a solution may be more apparent with the addional data.

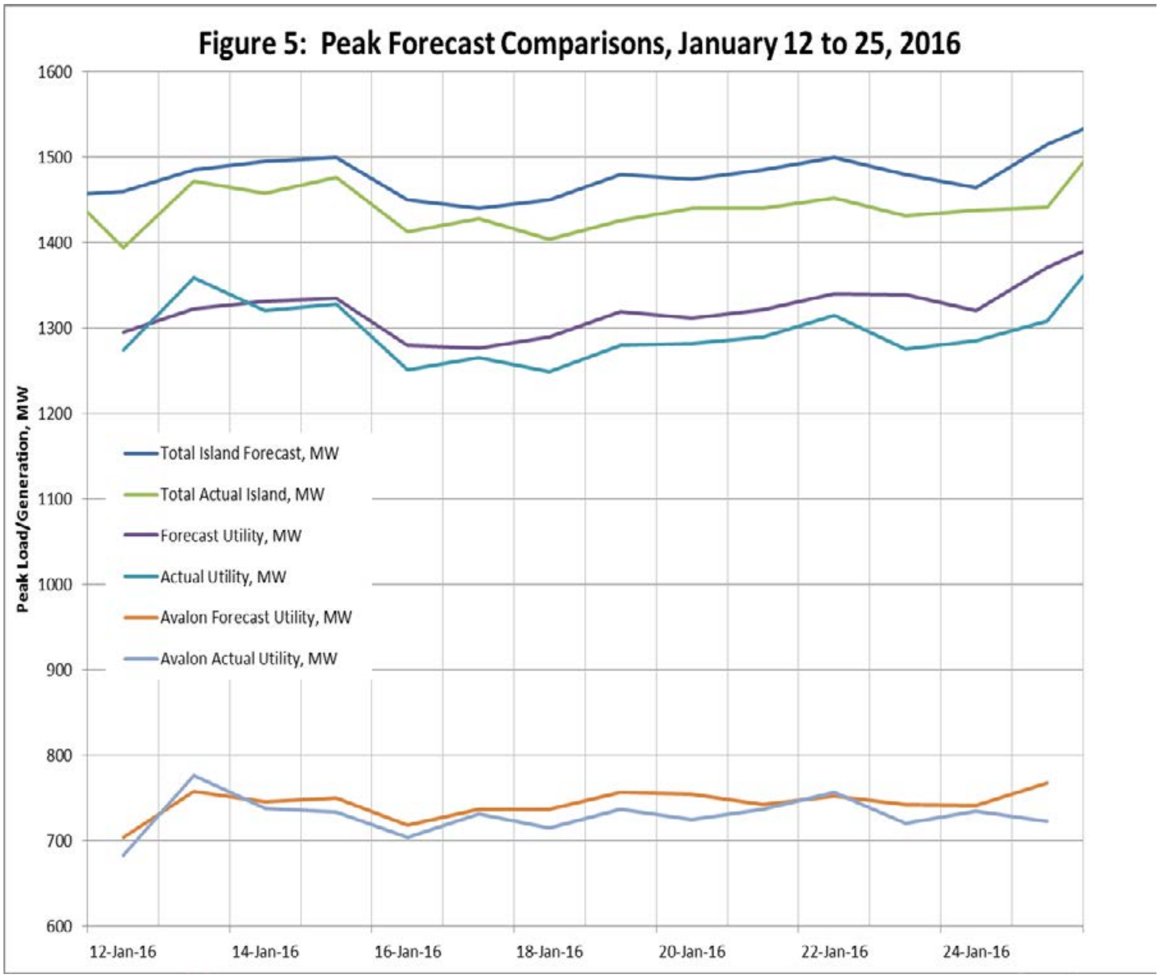
Figure 5: Peak Forecast Comparisons, January 12 to 25, 2016
1600
1500
1400
1300
1200
1100
1000
900
800
700
600
Peak Load/Generation, MW
Total Island Forecast, MW
Total Actual Island, MW
Forecast Utility, MW
Actual Utility, MW
Avalon Forecast Utility, MW
Avalon Actual Utility, MW
12-Jan-16
14-Jan-16
16-Jan-16
18-Jan-16
20-Jan-16
22-Jan-16
24-Jan-16

Figure 6 Daily Average Temperature Comparison, January 12 to 25 2016

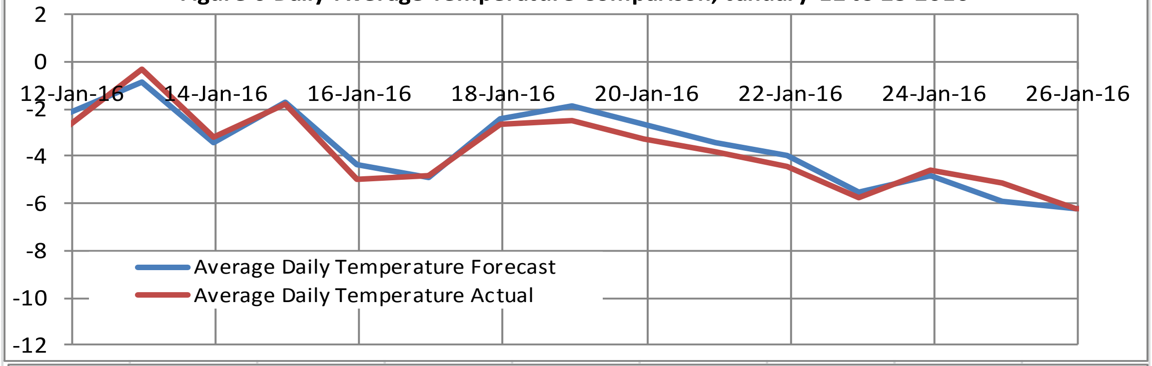

Figure 7 Daily Minimum Temperature Comparison, January 12 to 25 2016

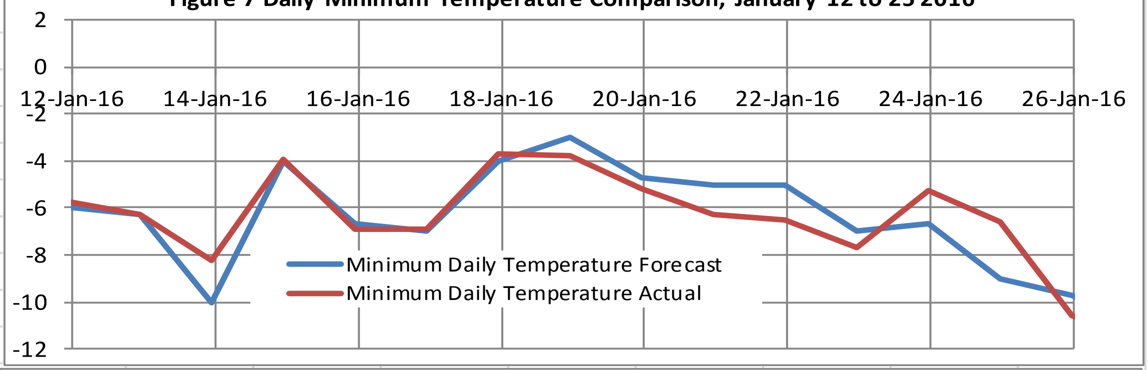

Figure 8 Daily Average Wind Speed Comparison, January 12 to 25 2016

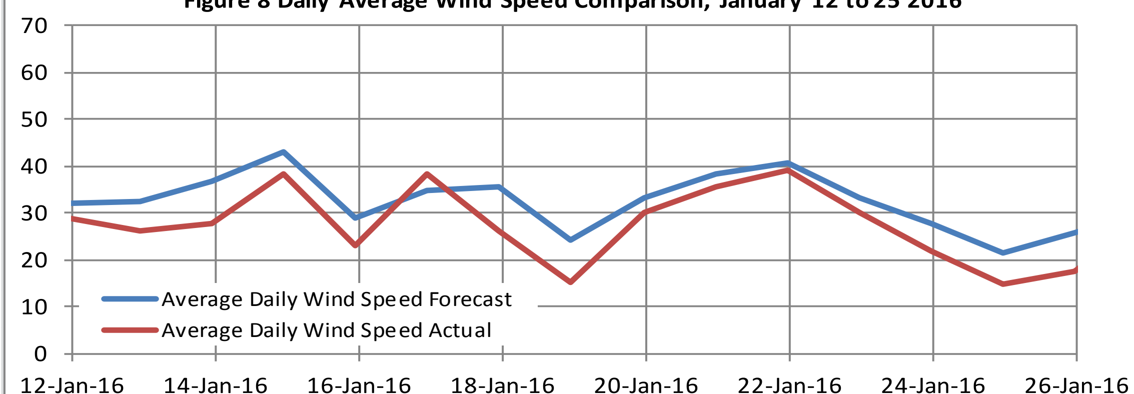

Figure 9 Daily Maximum Wind Speed Comparison, January 12 to 25 2016