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

December 1, 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: Newfoundland and Labrador Hydro's 2013 AMENDED General Rate Application - Revision**

Enclosed please find the original plus 12 copies of revisions to the following section of Hydro's Amended General Rate Application:

Volume II
Exhibit 2 – 2013 Annual Report on Key Performance Indicators.

The revision is necessary to provide updated information on pages E1, E2, E5, E27 – E33.

All revisions have been shaded for ease of reference.

Should you have any questions, please do not hesitate to 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 J. O'Reilly, Q.C. – Cox & Palmer
Senwung Luk – Olthuis, Kleer, Townshend LLP
Thomas Johnson – Consumer Advocate
Yvonne Jones, MP Labrador
Ed Hearn, Q.C. – Miller & Hearn

**A REPORT TO**
**THE BOARD OF COMMISSIONERS OF PUBLIC UTILITIES**

# *UPDATED EXHIBIT*

# 2013 ANNUAL REPORT
**ON**
# KEY PERFORMANCE INDICATORS
*Pursuant to Order No. P.U. 14 (2004)*

## NEWFOUNDLAND AND LABRADOR HYDRO

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# 1 Introduction

In Order No. P.U. 14 (2004), the Board required Newfoundland and Labrador Hydro (Hydro) to file appropriate historic, current and forecast comparisons of reliability, operating, financial and other Key Performance Indicators (KPIs). These were ordered to be filed with Hydro's annual financial report, commencing in 2004.

In compliance with the above Order, Hydro has 16 individual KPIs within the following four general categories: Reliability; Operating; Financial; and Customer-Related.

Within each of these categories, KPI data is reported on a historic basis for Hydro. Where appropriate, KPIs are subcategorized based on whether they relate to generation, transmission, distribution or overall corporate activity. For most of the Reliability KPIs, data from the Canadian Electricity Association (CEA) is provided in this report, as has been the case in prior years. CEA data has been published only to 2012. CEA data is unavailable for underfrequency load shedding, a reliability KPI, as this measure is unique to Hydro's Island Interconnected System. In the Operating category, the KPIs used to measure performance relate to two specific facilities within Hydro's system: Bay d'Espoir and Holyrood. For these two generation plants, performance is measured and compared on a year-over-year basis.

Section 2 of this report provides an overview of Hydro's KPI performance in 2013 compared with the prior year as well as a comparison of actual KPI results compared with targets. This is followed by a detailed analysis of each individual KPI within the four categories named above in Section 3.

Section 3.3 Financial Performance Indicators are not yet available but will follow after the audited financial statements are available.

The 2013 financial data and 2014 targets in Section 4 Data Table of Key Performance Indicators are not available at this time. This section will be re-filed after the financial data is available and the 2014 target levels have been established.

# 2 Overview of Key Performance Indicator Results

## *2.1 Performance in 2013 versus 2012*

There was an improvement in hydro plant performance in all measures, although overall generation performance was affected by a major failure of Holyrood Unit 1 on January 11. The performance of gas turbines was impacted by the extended planned outages of the Hardwoods and Happy Valley Gas Turbines. In addition the Stephenville Gas Turbine was not returned to service until June after a failure in December 2011.

The underfrequency load shedding performance target was not met in 2013 with a total of seven events.

Transmission and Distribution reliability declined in 2013 from 2012. There was a major interruption on January 11 which affected the entire system. Additionally, there were a number of severe weather related events which caused outages, primarily in the Northern and Central regions late in 2013.

The operating KPI for energy conversion showed a reduction in performance for the Holyrood fuel conversion rate. Unit operating time continued to be minimized in 2013, with units placed on line only as required to support Avalon Peninsula transmission and system peak loads.

The hydraulic conversion factor at Bay d'Espoir declined slightly in 2013 from 2012. In 2013, high water levels required that the plant be operated to reduce and control the spill of water, in particular during the summer and fall months.

Hydro's 2013 operating and maintenance costs are not available at this time. Financial KPI data will be provided at a later date.

The final category of KPIs called "Customer-Related" deals with Hydro's residential customer satisfaction. Customer satisfaction was not measured in 2013.

## *2.2 Performance in 2013 versus 2013 Target*

The table below summarizes Hydro's KPI performance in 2013 compared to targets set for each measure. Targets were not met for all reliability and operating measures due to a number of challenges further described in this report.

The rationale for the 2013 targets was summarized in the February 2013 report to the Board entitled *2012 Annual Report on Key Performance Indicators*. The 2013 rationale is included in this report as Appendix A.

| Hydro's KPI Targets and Operating Results for 2013 | | | | | |
|---|---|---|---|---|---|
| **Category** | **KPI** | **Units** | **2013 Target** | **2013 Results** | **Target Achieved** |
| Reliability | Weighted Capability Factor (WCF) | % | 84.0 | 75.5 | No |
| | DAFOR | % | 2.8 | 12.2 | No |
| | T-SAIDI | Minutes/Point | 203[1] | 468.5[2] | No |
| | T-SAIFI | Number/Point | 1.7[1] | 3.5[2] | No |
| | T-SARI | Minutes/Outage | 122[1] | 133.9[2] | No |
| | SAIDI | Hours/Customer | 5.9 | 18.6 | No |
| | SAIFI | Number/Customer | 3.6 | 5.7 | No |
| | Underfrequency Load Shedding | # of events | 6 | 7 | No |
| Operating | Hydraulic CF | GWh/MCM | 0.433 | 0.432 | No |
| | Thermal CF | kWh/BBL | 607 | 595 | No |
| Financial | Controllable Unit Cost | $/MWh | Not Applicable | 15.53 | |
| Other | Customer Satisfaction (Residential) | Max=100% | >90% | N/A | N/A |

[1] Transmission reliability targets were set on combined planned and unplanned outages.
[2] The transmission reliability indicator shown is for planned and unplanned outages.

# 3 Performance Indices

The following defines and describes detailed Key Performance Indicator data within four general categories: Reliability, Operating, Financial, and Customer-Related.

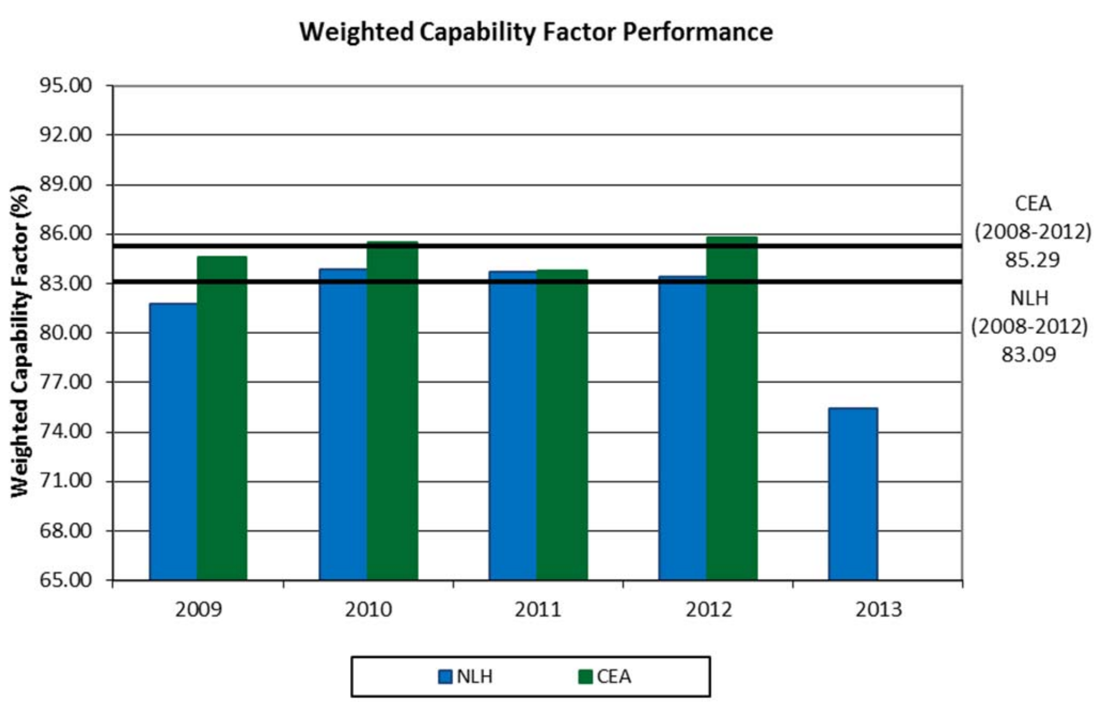
## *3.1 Reliability Performance Indicators*

Hydro monitors reliability performance with eight separate metrics. These metrics have been divided into the following subcategories: Generation, Transmission, Distribution, and Other.

### *3.1.1 Reliability KPI: Generation*

**3.1.1 a) Weighted Capability Factor (WCF) –** *a reliability KPI for generation assets that includes Hydro's thermal, gas turbine and hydroelectric generation assets on the Island and Labrador Interconnected Systems. The WCF measures the percentage of the time that a unit or a group of units is available to supply power at maximum continuous generating capacity. The factor is weighted to reflect the difference in generating unit sizes, meaning larger units have a greater impact on this measure.*

In 2013, Hydro's WCF was 75.5%. This is lower than the target of 84.0% and the 2008 to 2012 five-year average of 83.1%.



Thermal unit performance declined in 2013 to 46%, from 76% in 2012. Holyrood Unit 1 had the lowest capability factor of 22% while Holyrood Unit 2 had the highest capability factor of 72%. Unit 3 had a capability factor of 44%. On January 11, Unit 1 had a major bearing failure after the loss of lubricating oil during an unplanned shutdown. Investigation determined that the turbine and generator lubricating oil system failed to maintain sufficient oil to the bearings when the unit shut down as the result of a fault in the terminal station. Major repairs to the unit were required and the unit was release for service on October 9. Unit 3 was unavailable from May 22 to November 21 for two planned outages. These planned outages were to replace the unit's exciter and to replace the unit's protection and control panels.

Overall, the hydraulic unit performance improved slightly in 2013, to 92% compared to 91% in 2012. There were no major issues with the hydraulic generation and all units, except the Hinds Lake Unit which experienced a capability factor of 88% in 2013 due to a number of short duration planned outages.

Gas turbine performance improved to 65% in 2013 from 56% in 2012. The Stephenville unit failed in December 2011 due to a stator ground fault. This unit was release for service in June 2013. Performance of both Hardwoods and Happy Valley units was affected by planned outages of extended duration. Calculation details for weighted capability as well as a list of factors that may impact KPI performance are in Appendix B of this report.

The table below provides a comparison by unit type along with the weightings applied to the CEA values to provide for the comparison to Hydro for the period 2008-2012. Hydro's hydro generation capability was better than the comparable weighted national average. The weighted average is lower for Hydro's thermal-oil fired units and gas turbines.

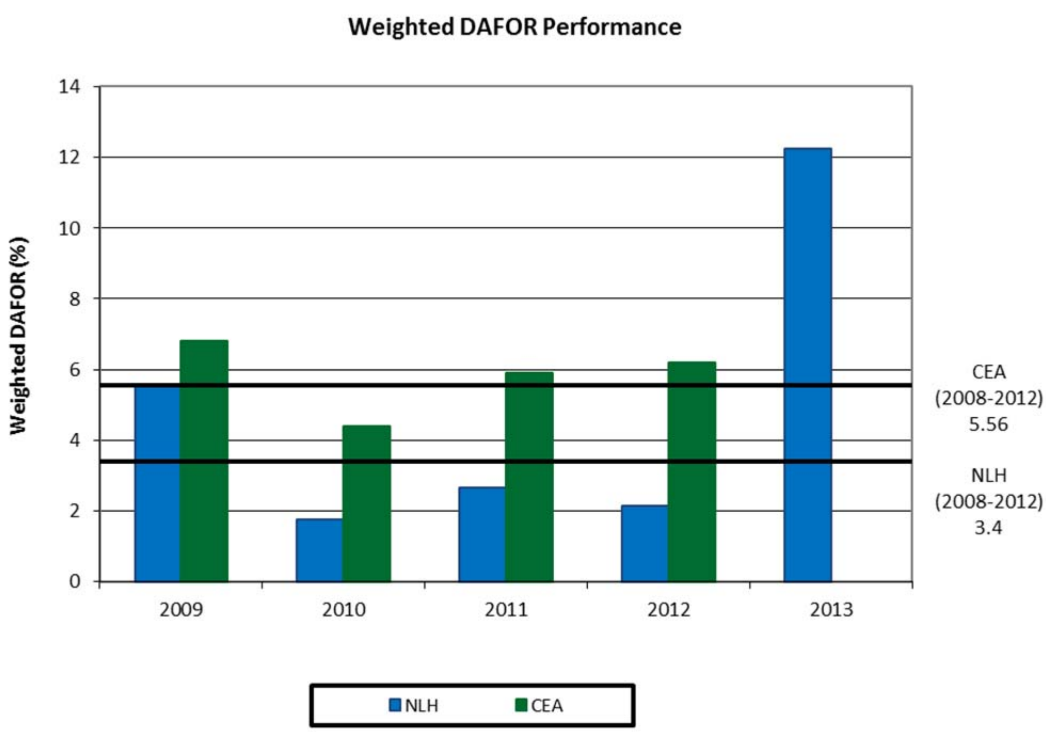
| Capability Factory Performance | | | |
|---|---|---|---|
| | **CEA (2008-2012)** | **NLH (2008-2012)** | **Weighting Factor** |
| Hydro | 86.19 | 92.22 | 60% |
| Thermal – Oil Fired | 74.38 | 66.00 | 31% |
| Gas Turbine | 90.67 | 70.05 | 9% |

The weighted national average is developed by using national average capabilities values for the unit types in Hydro's system (hydro, oil-fired thermal and gas turbine) and applying weightings to these based upon the maximum continuous ratings of Hydro's generation. The quoted CEA value is therefore not a CEA published value but a re-stated value to facilitate a comparison to Hydro.

**3.1.1 b) Weighted Derating-Adjusted Forced Outage Rate (DAFOR)** - *a reliability KPI for generation assets that includes Hydro's thermal and hydroelectric generation assets on the interconnected systems[3]. DAFOR measures the percentage of the time that a unit or group of units is unable to generate at its Maximum Continuous Rating (MCR) due to forced outages. The KPI is weighted to reflect differences in generating unit sizes.*

In 2013, Hydro's weighted DAFOR was 12.2% versus a target of 2.8%. The DAFOR was impacted by the major failure of Holyrood Unit 1, as described in the previous section. There were also issues with the excitation and fuel systems on Holyrood Unit 3 which affected the DAFOR. Hydro's overall weighted DAFOR for the period 2008 to 2012 (3.4%) is better than the equivalently weighted national average for the same period (5.6%). The following table provides a 2008-2012 comparison by unit type:

| DAFOR Performance | | | |
|---|---|---|---|
| | **CEA (2008-2012)** | **NLH (2008-2012)** | **Weighting Factor** |
| Thermal – Oil Fired | 9.33 | 9.97 | 34% |
| Hydro | 3.66 | 1.22 | 66% |




[3] DAFOR is not applicable to the gas turbines because of the gas turbines' low operating hours.

### *3.1.1.1 Generation Equipment Performance*

The table below highlights the various performance indices for Hydro's generation facilities. Indices for 2012 and for the latest Canadian Electricity Association national average for the period 2008-2012 are included for comparison.

**Generation Performance Indices**

| Index | | Hydro | Thermal | Gas Turbine |
|---|---|---|---|---|
| **Failure Rate** | NLH 2013 | 1.42 | 8.84 | 144.46 |
| (Forced Outages per 8,760 | NLH 2012 | 1.78 | 8.22 | 231.67 |
| operating hours) | CEA '08-'12 | 2.06 | 7.11 | 22.30 |
| **Incapability** | NLH 2013 | 7.97 | 53.96 | 26.73 |
| **Factor** | NLH 2012 | 9.26 | 26.92 | 31.28 |
| (Percent of Time) | CEA '08-'12 | 9.33 | 25.62 | 13.81 |
| **Derating Adjusted Forced** | NLH 2013 | 0.55 | 36.58 | |
| **Outage Rate** | NLH 2012 | 0.95 | 5.98 | |
| (Percent of Time) | CEA '08-'12 | 3.66 | 9.23 | |
| **Utilization** | NLH 2013 | | | 28.07 |
| **Forced Outage** | NLH 2012 | | | 56.33 |
| **Probability** (Percent of Time) | CEA '08-'12 | | | 11.84 |

#### 3.1.1.1 (a) Hydro Unit Performance

As indicated in the above Generation Performance Indices table, all hydro unit measures improved in 2013 when compared to 2012. In addition, all measures are better than the latest five-year national averages. Of particular note, is that the hydraulic unit derating adjusted forced outage rate continues to be significantly better than the latest five-year national average.

#### 3.1.1.1 (b) Thermal Unit Performance

Thermal unit performance deteriorated in 2013 in all measures. There was a decline in 2013 in the Incapability factor and derating adjusted forced outage rate measures and performance in these areas is now worse than the national five-year average. As indicated earlier, the decline is primarily due to the failure experienced at Holyrood Unit 1 and the resultant outage.

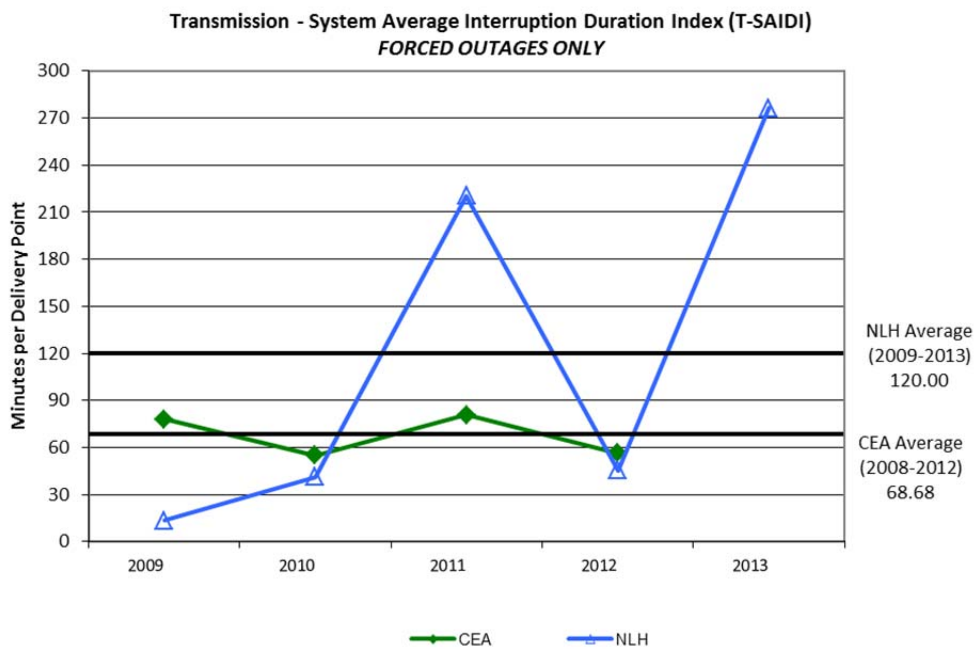
#### 3.1.1.1 (c) Gas Turbine Unit Performance

The Generation Performance Indices table indicates that Hydro's gas turbines performance improved in 2013 from 2012 for all measures. The Stephenville unit returned to service after a 20 month forced outage. However, extended planned outage at Hardwoods and Happy Valley limited the improvements seen. All measures continue to be worse than the national average. The failure rate calculation is very volatile due to the normally low operating hours of Hydro's gas turbines. Of particular importance to Hydro's use of gas turbines is the utilization forced outage probability (UFOP). The measure describes the degree to which a standby unit can be called upon to supply load when requested.

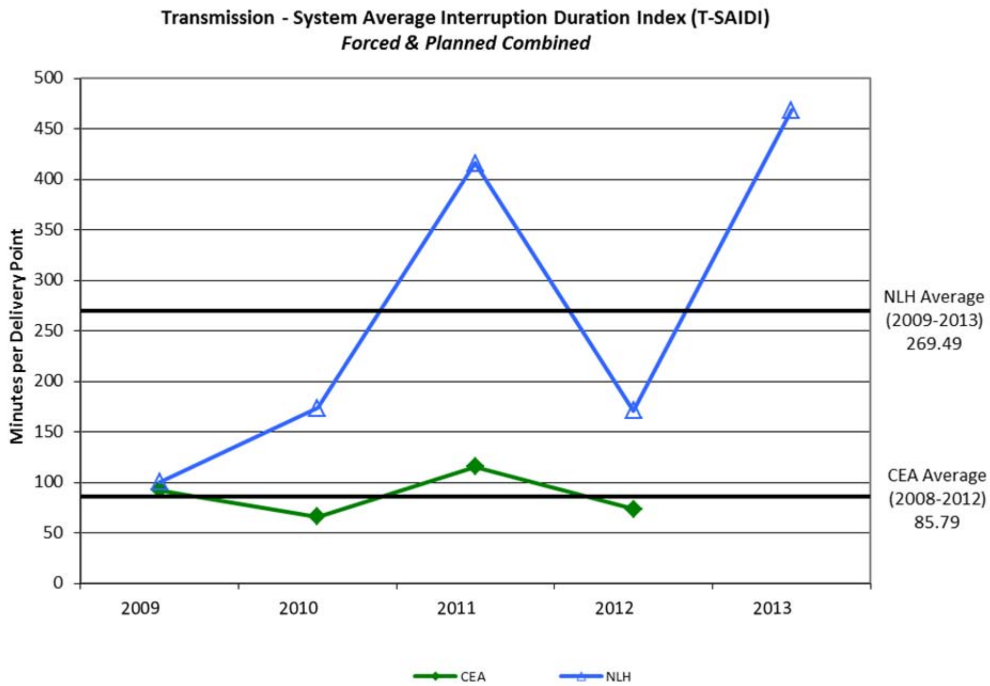
### *3.1.2 Reliability KPI: Transmission*

**3.1.2 a) Transmission System Average Interruption Duration Index (T-SAIDI)** - *reliability KPI for bulk transmission assets which measures the average duration of outages in minutes per delivery point.*

The fourth quarter T-SAIDI was 120 minutes per delivery point (forced and planned combined). The total 2013 T-SAIDI was 469 minutes per delivery point, 131% above the 2013 target[4] of 203 minutes per delivery point. In comparison, the 2012 total was 171 minutes per delivery point. The forced outage duration in 2013 increased to 277 minutes from 46 minutes in 2012. The planned outage duration increased to 192 minutes from 125 minutes in 2013.




[4] "Target" means less than or equal to the value set as a performance outcome.




There were a number of forced outages and four planned outages in the fourth quarter. A summary of these outages follows:

**<u>Forced</u>**

On October 30, customers supplied by the Parson's Pond Terminal Station experienced an unplanned power outage of one hour and 25 minutes. The outage was caused by salt contamination on transmission line TL227 (Daniel's Harbour to Parson's Pond section). Customers were restored from the Cow Head Terminal Station via TL227 (Cow Head to Parson's Pond section).

On November 21, customers supplied by the Parson's Pond Terminal Station experienced an unplanned power outage of nine minutes. The outage was required to safely close the bypass switch on the recloser at Parson's Pond.

On November 28, all customers on the Great Northern Peninsula experienced a series of unplanned power outages. Refer to the table below for additional detail. The outages were caused by a damaged insulator and broken jumper on TL227 and a transformer lockout on T1 at Berry Hill.

| Events on November 28, 2013 | | | | | |
|---|---|---|---|---|---|
| **Delivery Point Affected** | **Start Time** | **Finish Time** | **Duration of Interruptions (mins)** | **MW Load** | **MW-Mins** |
| | | | | | |
| Cow Head | 4:56:00 | 4:56:00 | 0 | 0.7 | 0.00 |
| Parson's Pond | 4:57:00 | 7:16:00 | 139 | 0.3 | 34.75 |
| Daniel's Harbour | 4:57:00 | 7:16:00 | 139 | 0.5 | 73.67 |
| Hawke's Bay | 4:57:00 | 6:13:00 | 76 | 2.7 | 202.92 |
| Plum Point | 4:57:00 | 7:19:00 | 142 | 1.6 | 225.78 |
| Bear Cove | 4:57:00 | 7:21:00 | 144 | 2.4 | 345.60 |
| Main Brook | 4:57:00 | 7:31:00 | 154 | 0.2 | 36.96 |
| Roddickton | 4:57:00 | 7:31:00 | 154 | 1.1 | 170.94 |
| St. Anthony Total | 4:57:00 | 6:52:00 | 115 | 5.1 | 586.50 |
| St. Anthony Line 1 | 4:57:00 | 6:35:00 | 98 | 1.4 | 137.20 |
| St. Anthony Line 2 | 4:57:00 | 6:52:00 | 115 | 1.1 | 126.50 |
| St. Anthony Line 3 | 4:57:00 | 6:21:00 | 84 | 2.5 | 210.00 |
| Wiltondale | 5:16:00 | 5:19:00 | 3 | 0.1 | 0.30 |
| Glenburnie | 5:16:00 | 5:19:00 | 3 | 1.3 | 3.90 |
| Rocky Harbour | 5:16:00 | 5:19:00 | 3 | 1.9 | 5.70 |
| Wiltondale | 5:22:00 | 5:26:00 | 4 | 0.1 | 0.40 |
| Glenburnie | 5:22:00 | 5:26:00 | 4 | 1.4 | 5.60 |
| Rocky Harbour | 5:22:00 | 5:26:00 | 4 | 2.0 | 8.00 |
| Hawke's Bay Line 1 | 6:17:00 | 6:34:00 | 17 | 1.1 | 18.70 |
| Cow Head | 4:57:00 | 9:15:00 | 258 | 0.6 | 154.80 |
| St. Anthony Total | 8:53:00 | 8:58:00 | 5 | 8.4 | 42.00 |
| St. Anthony Line 1 | 8:53:00 | 8:57:00 | 4 | 2.1 | 8.40 |
| St. Anthony Line 2 | 8:53:00 | 8:57:00 | 4 | 1.8 | 7.50 |
| St. Anthony Line 3 | 8:53:00 | 8:58:00 | 5 | 3.8 | 19.00 |
| Cow Head | 10:17:00 | 16:50:00 | 393 | 1.0 | 393.00 |
| Parson's Pond | 10:37:00 | 16:39:00 | 362 | 0.4 | 144.80 |
| | | **Totals** | 2,429 | 45.60 | 2,334.12 |

On November 21, customers supplied by the South Brook Terminal Station experienced unplanned power outages of two minutes and one minute. Both outages resulted from a trip of TL222 during a winter storm with high winds and wet snow.

There was another outage on November 21 affecting customers supplied by the South Brook Terminal Station. This was an unplanned power outage of eight hours and 50 minutes. The outage was caused by seven damaged structures in transmission line TL222; the result of a winter storm with high winds and wet snow. Customers were also impacted when the winter storm caused damage to the distribution system in South Brook.

On December 4, all customers on the Great Northern Peninsula, north of Cow Head experienced an unplanned power outage (see table below). The outages were caused by a tree contact on TL239. The following is a table summarizing the customer interruptions:

| Delivery Point Affected | Start Time | Time of Restoration | Outage Duration (mins) | Load Loss (MW) | MW-Mins |
|---|---|---|---|---|---|
| Cow Head | 7:36 | 7:44 | 11 | 1 | 11 |
| Parson's Pond | 7:36 | 7:45 | 9 | 0.5 | 4.5 |
| Daniel's Harbour | 7:36 | 7:45 | 9 | 0.5 | 4.5 |
| Hawkes's Bay | 7:36 | 7:44 | 8 | 4.3 | 34.4 |
| Plum Point | 7:36 | 7:47 | 11 | 2.3 | 25.3 |
| Bear Cove | 7:36 | 7:48 | 12 | 3.6 | 43.2 |
| Main Brook | 7:36 | 8:00 | 24 | 0.34 | 8.16 |
| Roddickton | 7:36 | 8:00 | 24 | 1.8 | 43.2 |
| St Anthony | 7:36 | 9:09 | 93 | 7.5 | 551.4 |

**Planned**

On November 3, customers supplied by the Bear Cove and Plum Point Terminal Stations experienced a planned power outage of six hours and 18 minutes. The outage was required to perform corrective and preventative maintenance on 138 kV equipment at Peter's Barren, to replace a potential transformer on C Phase on TL241 at Plum Point, to replace the TL241 potential transformer cabinet, and to perform preventative and corrective maintenance on all 138 kV equipment and switchgear at Bear Cove. Customers in Main Brook, Roddickton, and St. Anthony were supplied via the St. Anthony Diesel Plant during this outage.

On November 8, Newfoundland Power customers supplied by Springdale Terminal Station experienced a planned power outage of four hours and 39 minutes. The outage was required to remove a temporary station bypass, to commission a new breaker - B1L22, to perform preventive and corrective maintenance on disconnect switches, to doble test TL223 potential transformer, and to replace dead-end insulators in the station.

On December 18, customers supplied by the Bear Cove, Plum Point, Main Brook and Roddickton Terminal Stations experienced a planned power outage of 24 minutes. The outage was required to energize mobile substation P-235 at Hawke's Bay.

On December 19, customers supplied by the Conne River, English Harbour West, and Barachoix Terminal Stations and customers in the Bay d'Espoir distribution area experienced a planned power outage of 24 minutes. The outage was required to energize the new B13L20 circuit breaker.

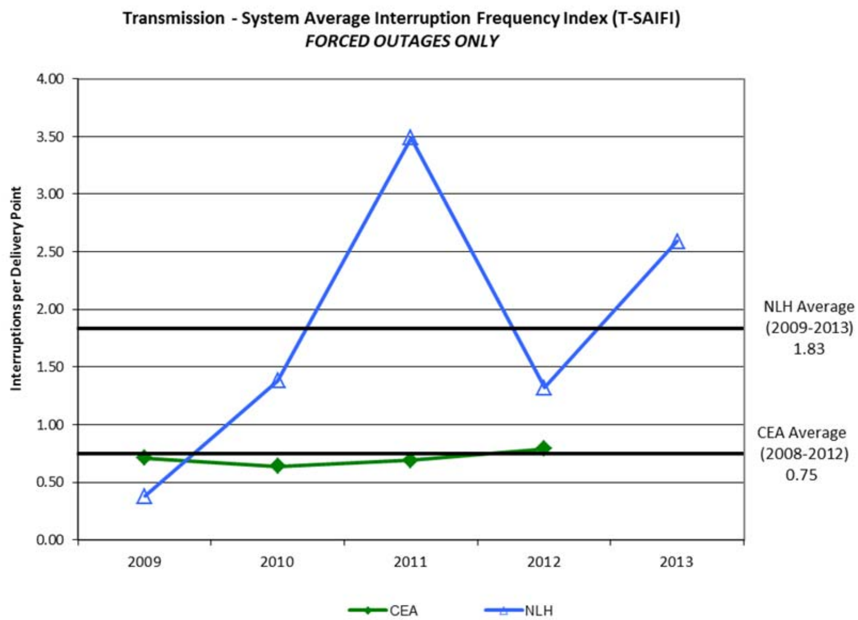
**3.1.2 b) Transmission System Average Interruption Frequency Index (T-SAIFI)** - *a reliability KPI for bulk transmission assets that measures the average number of sustained outages per delivery point*.

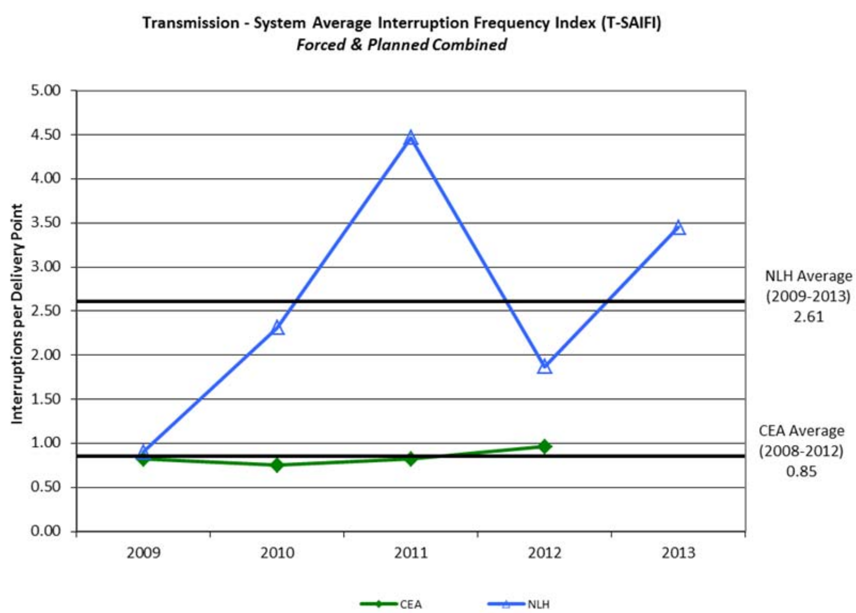
The fourth quarter T-SAIFI was 0.91 outages per bulk delivery point, with contributions of forced and planned outage frequency of 0.55 and 0.36, respectively. In comparison, the 2012 fourth quarter T-SAIFI was 0.52 outages per bulk delivery point. The increase in outage frequency was primarily the result of a higher number of planned outages this quarter.

The overall 2013 T-SAIFI was 3.45 outages per bulk delivery point which is significantly higher than last year's average of 1.91 outages per delivery point, an increase of 81%. The 2013 target was 1.66 outages per bulk delivery point and was not met. The number of forced outages per delivery point in

2013 (2.59) increased by 90% from 2012 (1.36). The number of planned outages per delivery point in 2013 (0.86) increased by 56% from 2012.

The frequency of Hydro's forced delivery point outages has been generally higher than the national average. This result is expected and can generally be attributed to the number of delivery points that are supplied by a single transmission line. The most severe example is on the Great Northern Peninsula, where one line, TL239, supplies up to nine delivery points. There are a number of other locations where a single line supplies three delivery points.



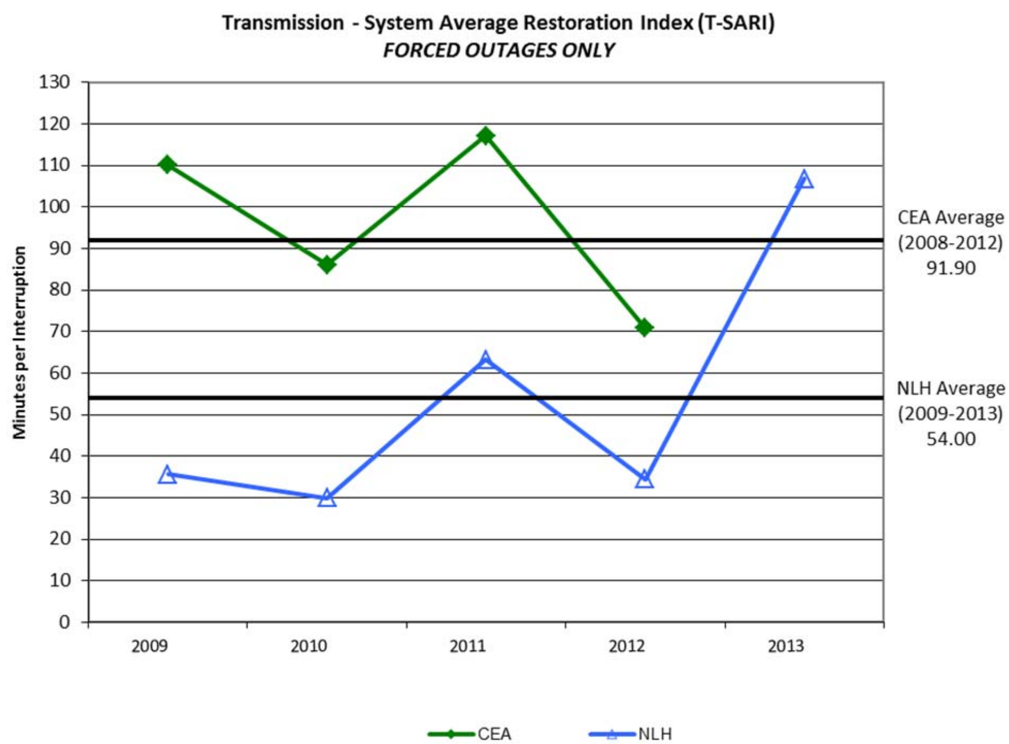



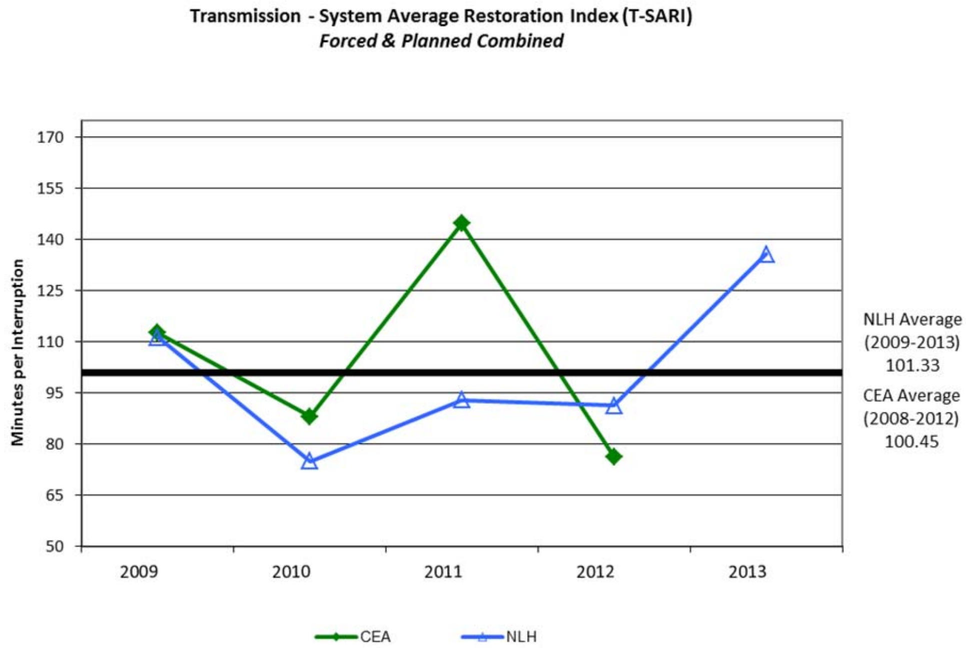
**3.1.2 c) Transmission System Average Restoration Index (T-SARI)** - *reliability KPI for bulk transmission assets which measures the average duration per transmission interruption. T-SARI is calculated by dividing T-SAIDI by T-SAIFI.*

Hydro's total transmission T-SARI was 131 minutes per interruption for the fourth quarter of 2013 compared to 62 minutes per interruption during the same quarter in 2012, a 111% increase. The forced outage component of T-SARI was 91 minutes per interruption compared to 41 minutes per interruption in 2012. The planned outage component of T-SARI was 192 minutes per interruption which is 4% lower than during the fourth quarter of 2012.

Hydro's 2013 total transmission T-SARI was 136 minutes per interruption, compared to 90 minutes in 2012 and a 2013 target of 123 minutes. The forced outage component of T-SARI was 107 minutes per interruption, an increase of 105% over 2012. The planned outage component of T-SARI was 223 minutes per interruption, which is an approximately the same value as 2012. Since T-SARI is the ratio of T-SAIDI to T-SAIFI, this increase is driven by greater increase in T-SAIDI relative to T-SAIFI.

Hydro's total T-SARI performance deteriorated in 2013 and is now below the latest five-year national average. This can be seen in the chart below.

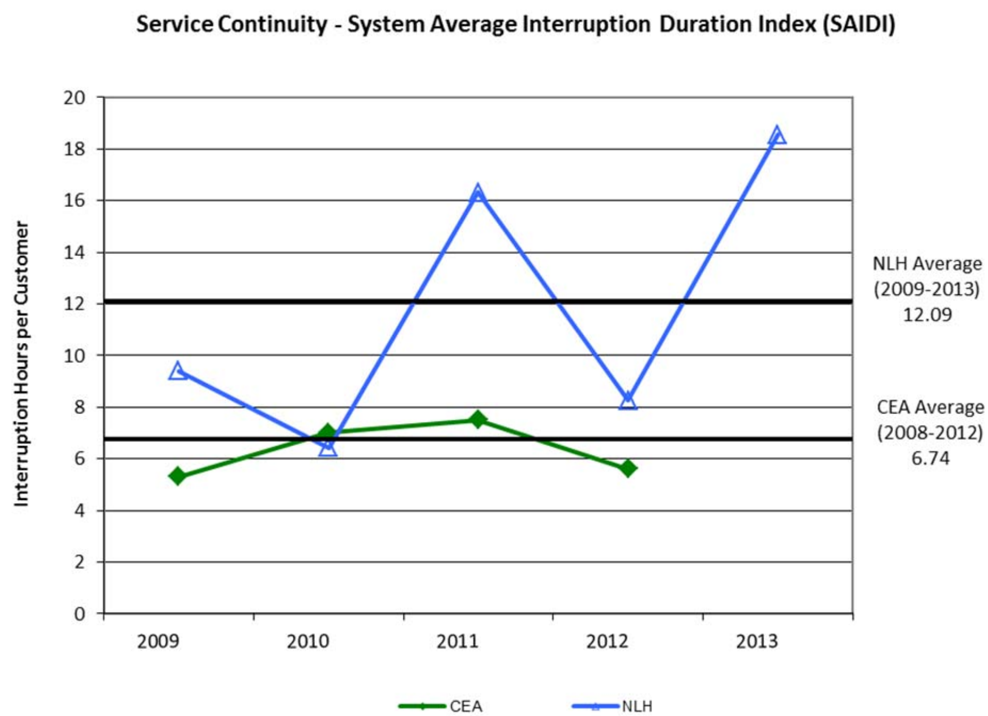



Transmission - System Average Restoration Index (T-SARI)
Forced & Planned Combined
Minutes per Interruption
170
155
140
125
110
95
80
65
50
2009
2010
2011
2012
2013
NLH Average (2009-2013) 101.33
CEA Average (2008-2012) 100.45
CEA
NLH

### *3.1.3 Reliability KPI: Distribution*

**3.1.3 a) System Average Interruption Duration Index (SAIDI)** - *a reliability KPI for distribution service and it measures service continuity in terms of the average cumulative duration of outages per customer served during the year.*

In the fourth quarter of 2013, the SAIDI was 4.35 hours per customer, compared to 3.43 hours per customer during the same quarter of 2012. The total 2013 SAIDI was 18.56 hours per customer, compared to 8.31 hours per customer in 2012. The performance in 2013 was 215% worse than the annual target of 5.90 hours per customer.



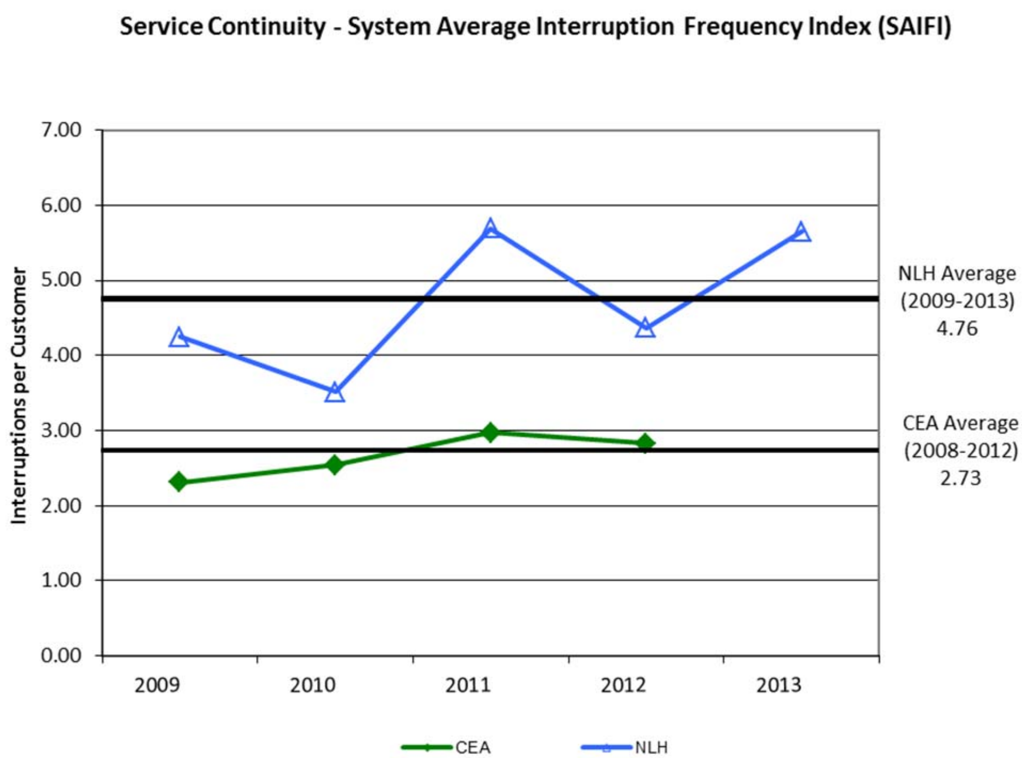

The outages during the fourth quarter resulted from a variety of causes. The following table presents a summary of the major interruptions.

| Distribution System | Outage Date | Outage Cause | Customers Affected | Outage Duration (Hours) | Notes |
|---|---|---|---|---|---|
| Seal Cove Road | Nov 02, 2013 | Tree Contacts | 253 | 9.50 | Trees fell on main feeder conductor. Trees had to be removed before customers could be restored |
| St. Anthony | Nov 18, 2013 | Sched Outage-Planned | 505 | 5.00 | Planned outageto install new insulators on the main feeder line. |
| Bottom Waters | Nov 21, 2013 | Tree Contacts | 379 | 37.70 | Tree fell on line and broke conductor |
| Bottom Waters | Nov 21, 2013 | Adverse Weather | 442 | 23.83 | Insulator broke due to weather conditons. High winds and blowing wet snow. |
| Roddickton | Nov 21, 2013 | Adverse Weather | 554 | 12.38 | Tree on line burnt off conductor |
| Kings Point | Nov 21, 2013 | Tree Contacts | 535 | 11.82 | Trees fell on main feeder conductor. Trees had to be removed before customers could be restored |
| Glenbernie | Nov 21, 2013 | Environment-Salt Spray | 299 | 6.82 | High Winds/Salt Spray |
| Wabush | Nov 21, 2013 | Sched Outage-Planned | 157 | 6.33 | Planned outage - substation work |
| Parson's Pond | Nov 21, 2013 | Adverse Weather | 271 | 5.80 | Recloser failed to close automatically. Workers closed the recloser locally. |
| St. Lewis | Nov 21, 2013 | Weather-Gallop Conduc | 129 | 5.17 | Damaged insulator due to ice storm |
| Kings Point | Nov 21, 2013 | Adverse Weather | 632 | 3.82 | Trees fell on main feeder conductor. Trees had to be removed before customers could be restored |
| South Brook | Nov 22, 2013 | Tree Contacts | 756 | 28.33 | Trees fell on main feeder conductor. Trees had to be removed before customers could be restored |
| Bottom Waters | Nov 22, 2013 | Adverse Weather | 194 | 24.17 | Main feeder line was damaged due to winter storm. Repairs to the line hardware were required before customer could be restored. |
| South Brook | Nov 22, 2013 | Tree Contacts | 596 | 23.75 | Trees fell on main feeder conductor. Trees had to be removed before customers could be restored |
| Bottom Waters | Nov 22, 2013 | Adverse Weather | 194 | 22.33 | Insulator and crossarm broken/winter storm damage |
| St. Anthony | Nov 23, 2013 | Sched Outage-Planned | 505 | 6.42 | Install new equipment on main feeder |
| Wabush | Nov 24, 2013 | Sched Outage-Planned | 155 | 5.50 | Planned outage - substation work |
| Bottom Waters | Nov 26, 2013 | Adverse Environment | 194 | 3.12 | Wind broke pole at base |
| Wabush | Nov 29, 2013 | Foreign Int-Vehicle | 1455 | 7.58 | Heavy Equipment contacted line |
| Farewell Head | Dec 02, 2013 | Foreign Int-Vehicle | 200 | 8.00 | Truck hooked and broke main conductor/damaged pole |

The remainder of the significant events in 2013 affecting the distribution systems (i.e., outages generally to a complete system with duration of greater than five hours) are contained in Appendix C2.

**3.1.3 b) System Average Interruption Frequency Index (SAIFI)** - *reliability KPI for distribution service which measures the average cumulative number of sustained interruptions per customer per year.*

In the fourth quarter the SAIFI was 1.24 interruptions per customer, compared to 1.64 interruptions per customer during the same quarter of 2012, a 24% decrease. The total 2013 SAIFI was 5.65 interruptions per customer compared to 4.40 interruptions per customer in 2012, a 28% increase. The 2013 target of 3.65 interruptions per customer was not met; the performance in 2013 deteriorated from what had been an improvement in 2012.




### *3.1.3.1 Additional Information*

This section provides more detailed information in three tables with performance broken down by Area, Origin, and Type.

**Rural Systems Service Continuity Performance by Area**

| SAIFI (Number per Period) | | | | | |
|---|---|---|---|---|---|
| **Area** | **Fourth Quarter** | | **12 Mths to Date** | | **5 Year** |
| | **2013** | **2012** | **2013** | **2012** | **Average** |
| **Central** | | | | | |
| Interconnected | 0.65 | 0.89 | 3.96 | 2.05 | 2.84 |
| Isolated | 0.01 | 0.85 | 2.85 | 2.68 | 3.49 |
| **Northern** | | | | | |
| Interconnected | 1.70 | 2.31 | 4.68 | 4.81 | 4.16 |
| Isolated | 1.44 | 5.03 | 4.80 | 8.65 | 6.20 |
| **Labrador** | | | | | |
| Interconnected | 1.42 | 1.10 | 8.41 | 5.44 | 6.64 |
| Isolated | 2.32 | 3.51 | 9.11 | 9.59 | 10.56 |
| Total | 1.24 | 1.64 | 5.65 | 4.40 | 4.76 |

Note: System Average Interruption Frequency Index (SAIFI) is the average number of interruptions per customer. It is calculated by dividing the number of customers that have experienced an outage by the total number of customers in an area

| SAIDI (Hours per Period) | | | | | |
|---|---|---|---|---|---|
| **Area** | **Fourth Quarter** | | **12 Mths to Date** | | **5 Year** |
| | **2013** | **2012** | **2013** | **2012** | **Average** |
| **Central** | | | | | |
| Interconnected | 6.84 | 2.31 | 20.75 | 4.97 | 11.20 |
| Isolated | 0.05 | 2.13 | 2.55 | 4.93 | 2.94 |
| **Northern** | | | | | |
| Interconnected | 5.11 | 5.73 | 11.06 | 11.05 | 10.92 |
| Isolated | 0.94 | 5.36 | 6.07 | 6.89 | 6.27 |
| **Labrador** | | | | | |
| Interconnected | 2.06 | 2.17 | 27.95 | 9.28 | 16.27 |
| Isolated | 1.42 | 4.92 | 8.24 | 15.11 | 12.01 |
| Total | 4.35 | 3.43 | 18.56 | 8.31 | 12.09 |

Note: System Average Interruption Duration Index (SAIDI) is the average interruption duration per customer. It is calculated by dividing the number of customer-outage-hours (e.g. a two-hour outage affecting 50 customers equals 100 customer-outage-hours) by the total number of customers in an area.

## Rural Systems Service Continuity Performance by Origin

**SAIFI (Number per Period)**

| Area | Fourth Quarter 2013 | Fourth Quarter 2012 | 12 Mths to Date 2013 | 12 Mths to Date 2012 | 5 Year Average |
|---|---|---|---|---|---|
| Loss of Supply – Transmission | 0.26 | 0.23 | 1.31 | 1.39 | 1.53 |
| Loss of Supply – NF Power | 0.00 | 0.00 | 0.00 | 0.01 | 0.01 |
| Loss of Supply – Isolated | 0.12 | 0.21 | 0.49 | 0.53 | 0.53 |
| Loss of Supply – L'Anse au Loup | 0.00 | 0.00 | 0.05 | 0.03 | 0.06 |
| Distribution | 0.86 | 1.20 | 3.79 | 2.45 | 2.63 |
| Total | 1.24 | 1.64 | 5.65 | 4.40 | 4.76 |

Note: System Average Interruption Frequency Index (SAIFI) is the average number of interruptions per customer. It is calculated by dividing the number of customers that have experienced an outage by the total number of customers.

**SAIDI (Hours per Period)**

| Area | Fourth Quarter 2013 | Fourth Quarter 2012 | 12 Mths to Date 2013 | 12 Mths to Date 2012 | 5 Year Average |
|---|---|---|---|---|---|
| Loss of Supply – Transmission | 0.55 | 0.23 | 4.35 | 1.70 | 3.65 |
| Loss of Supply – NF Power | 0.00 | 0.00 | 0.01 | 0.00 | 0.14 |
| Loss of Supply – Isolated | 0.04 | 0.10 | 0.21 | 0.34 | 0.24 |
| Loss of Supply – L'Anse au Loup | 0.00 | 0.00 | 0.05 | 0.00 | 0.04 |
| Distribution | 3.76 | 3.10 | 13.94 | 6.26 | 8.02 |
| Total | 4.35 | 3.43 | 18.56 | 8.31 | 12.09 |

Note: System Average Interruption Duration Index (SAIDI) is the average interruption duration per customer. It is calculated by dividing the number of customer-outage-hours (e.g. a two-hour outage affecting 50 customers equals 100 customer-outage-hours) by the total number of customers in an area.

## Rural Systems Service Continuity Performance by Type

| Area | Scheduled | | Unscheduled | | Total | |
|---|---|---|---|---|---|---|
| | SAIFI | SAIDI | SAIFI | SAIDI | SAIFI | SAIDI |
| **Central** | | | | | | |
| Interconnected | 0.06 | 0.15 | 0.59 | 6.69 | 0.65 | 6.84 |
| Isolated | 0.00 | 0.00 | 0.01 | 0.05 | 0.01 | 0.05 |
| **Northern** | | | | | | |
| Interconnected | 0.12 | 0.60 | 1.58 | 4.50 | 1.70 | 5.11 |
| Isolated | 0.00 | 0.00 | 1.44 | 0.94 | 1.44 | 0.94 |
| **Labrador** | | | | | | |
| Interconnected | 0.54 | 0.55 | 0.88 | 1.51 | 1.42 | 2.06 |
| Isolated | 0.18 | 0.38 | 2.13 | 1.04 | 2.32 | 1.42 |
| Total | 0.21 | 0.38 | 1.03 | 3.97 | 1.24 | 4.35 |

Note:

1. System Average Interruption Frequency Index (SAIFI) is the average number of interruptions per customer. It is calculated by dividing the number of customers that have experienced an outage by the total number of customers in an area.

2. System Average Interruption Duration Index (SAIDI) is the average interruption duration per customer. It is calculated by dividing the number of customer-outage-hours (e.g. a two-hour outage affecting 50 customers equals 100 customer-outage-hours) by the total number of customers in an area.

### *3.1.4 Reliability KPI: Other*

**3.1.4 a) Under Frequency Load Shedding (UFLS)** - *reliability KPI that measures the number of events in which shedding of a customer load is required to counteract a generator trip. Customer loads are shed automatically depending upon the generation lost.*

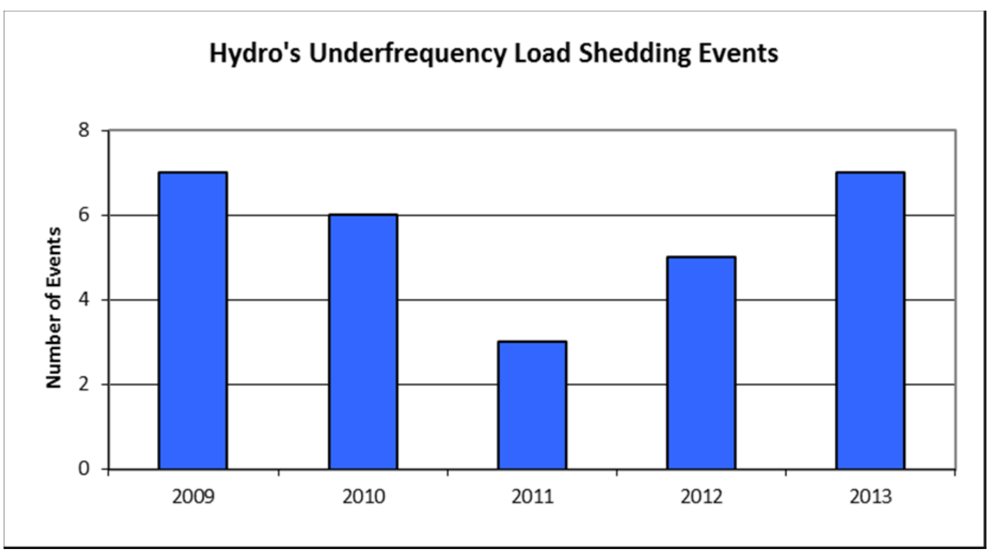
There was one underfrequency event during the fourth quarter of 2013, summarized as follows:

On November 29 at 1813 hours, Holyrood Generating Unit 1 tripped. The unit trip was the result of the main stop valve closing during daily valve testing. With the removal of generation (approximately 119 MW), the system frequency dropped to 58.78 Hz resulting in the activation of the under frequency protection at Newfoundland Power. Total system load at the time of the incident was 1,034 MW. There were 6,764 Newfoundland Power customers reported to be restored within ten minutes after the event occurred. (Unsupplied Energy: 175 MW-Mins).

Load Shed:

Newfoundland Power: 25 MW
Total Load Shed: 25 MW

In total, there were seven UFLS events in 2013. This represents two more events than the experience in 2012, and above the five-year average of 5.6 events. Refer to the graph below which compares the UFLS events over the past five years to this year's performance.




The following table compares the UFLS events in the fourth quarter of 2013 to the same quarter in 2012.

| Underfrequency Load Shedding Number of Events | | | | | |
|---|---|---|---|---|---|
| Customers | Fourth Quarter | | Year to Date | | 5 Year Average |
| | 2013 | 2012 | 2013 | 2012 | (2009–2013) |
| NF Power | 1 | 3 | 7 | 5 | 5.6 |
| Industrials | 0 | 0 | 0 | 1 | 1.6 |
| Hydro Rural* | 0 | 2 | 3 | 3 | 2.2 |
| Total Events | 1 | 3 | 7 | 5 | 5.6 |

| Underfrequency Load Shedding Unsupplied Energy (MW-min) | | | | | |
|---|---|---|---|---|---|
| Customers | Fourth Quarter | | Year to Date | | 5 Year Average |
| | 2013 | 2012 | 2013 | 2012 | (2009–2013) |
| NF Power | 175 | 920 | 13,917 | 3,194 | 3,854 |
| Industrials | 0 | 0 | 0 | 140 | 115 |
| Hydro Rural* | 0 | 86 | 324 | 107 | 95 |
| Total Events | 175 | 1,006 | 14,241 | 3,440 | 4,064 |

* Underfrequency activity affecting Hydro Rural Customers may also result in a number of delivery point outages. Outage frequency and duration are also included in totals shown in the delivery point statistics section of the report for these areas, namely the Connaigre Peninsula and Bonne Bay.

The details of the previous six UFLS events in 2013 are summarized in Appendix C3.

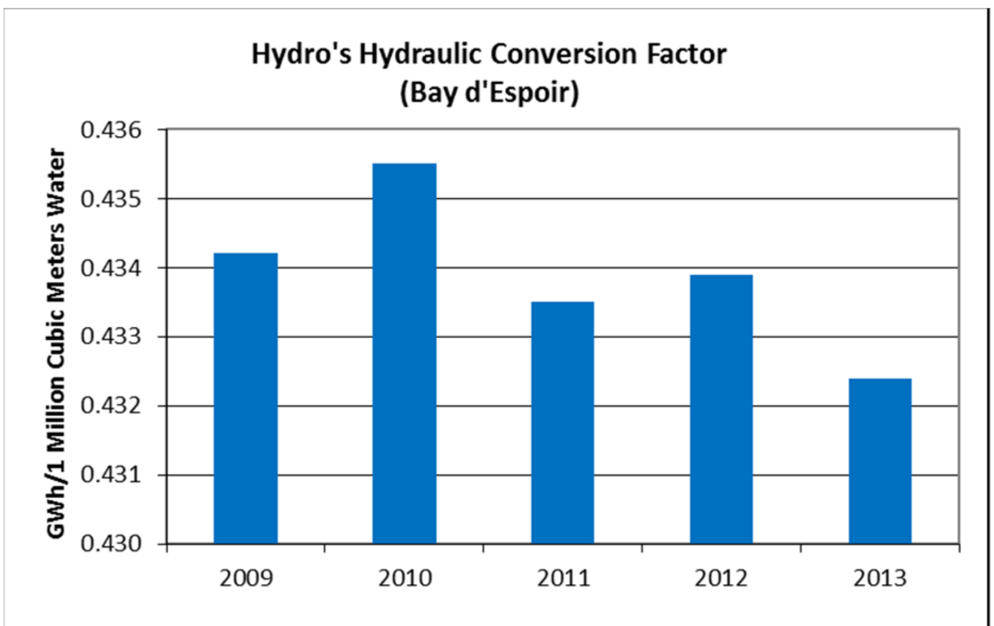
## 3.2 Operating Performance Indicators

This section presents information on two indicators of operating performance, both of which are associated with generation.

### *3.2.1 Operating KPI: Generation*

**3.2.1 a) Hydraulic Conversion Factor (Bay d'Espoir)** - *a representative performance KPI for the principal hydroelectric generation assets located at Bay d'Espoir. This KPI tracks the efficiency in converting water to energy and it is calculated as the ratio of Net GWh generated for every one million cubic metres (MCM) of water consumed.*

In 2013, Hydro's hydraulic conversion factor for Bay d'Espoir was 0.4324 GWh/MCM. The performance in 2013 declined from 2012, primarily due to reservoir storages which were very high. This required that generation be operated at high levels in order to minimize spill or the potential for spill. The requirement to control the amount of spill resulted in less efficient operation of the hydro-electric generation.

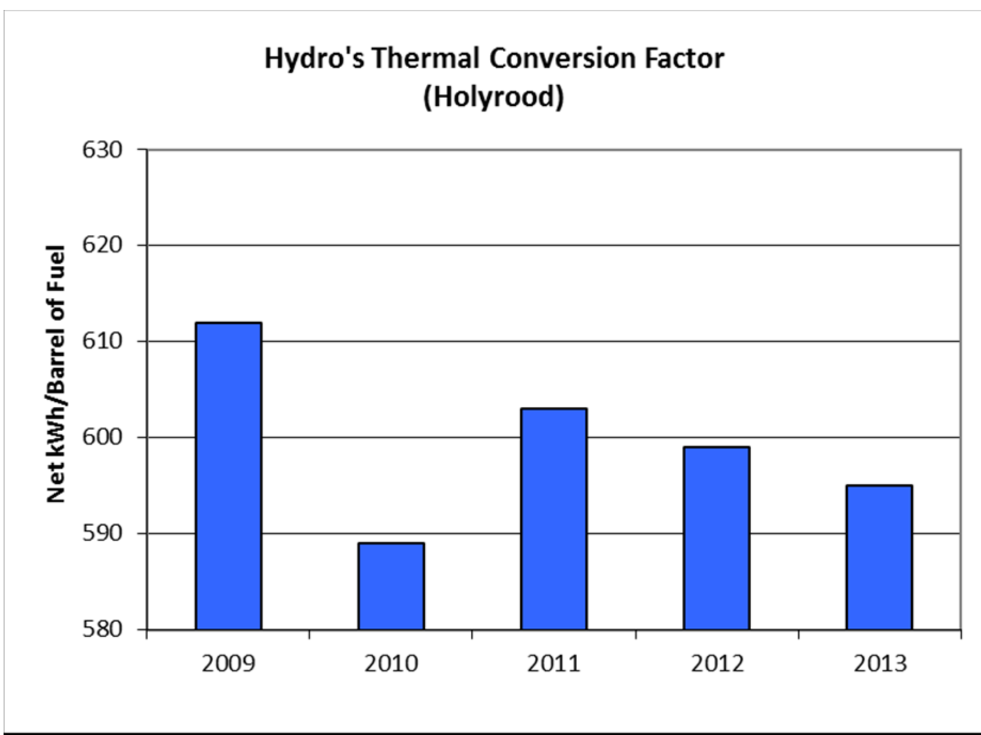


**3.2.1 b) Thermal Conversion Factor -** *a representative performance KPI for the oil-fired thermal generation assets located at Holyrood. This KPI tracks the efficiency in converting heavy fuel oil into electrical energy and is measured as the ratio of the net kWhs generated to the number of barrels of No. 6 fuel oil consumed.*

The thermal conversion factor for Holyrood is directly proportional to the output level of the three units, with higher averages and sustained loadings resulting in higher conversion factors. In turn, the output level of the Holyrood Thermal Generating Station will vary depending on hydraulic production, quantity of power purchases, customer energy requirements and system security requirements.

In 2013, Hydro's net thermal conversion factor was 595 kWh per barrel, which is below the 2013 target of 607 kWh per barrel. The low energy conversion rate is primarily related to operating the plant at lower generating levels due to the high volume of water resources and energy receipts relative to the system load requirements. The experience in 2013 continued the decline which was seen in 2012 from an improvement in 2011.

Production at Holyrood was kept to a minimum in 2013 with units dispatched only as required for Avalon transmission support and system peak load considerations. The average net unit load while operating was 88 MW, up from 80 MW in 2012. Overall, net production from Holyrood for 2013 was 957 GWh, an 11.9% increase from 2012 production levels.



## *3.3 Financial Performance Indicators [complete section updated]*

The financial KPIs reported annually to the Board are:

1. Corporate operating, maintenance and administrative expense (OM&A) per MWh delivered;
2. Generation OM&A per MW installed capacity;
3. Generation OM&A per GWh generated;
4. Transmission OM&A per transmission circuit km; and
5. Distribution OM&A per distribution circuit km.[5]

In Order No. P.U. 8 (2007), the Board ordered that Hydro file a report no later than October 31, 2007 outlining an appropriate peer group with which Hydro's financial performance at the generation and transmission levels could be compared. In compliance with Board Order No. P.U. 8(2007), Hydro filed a report titled "Peer Group Benchmarking" dated October 31, 2007 which summarized Hydro's findings regarding development of a peer group for financial KPIs related to generation and transmission. In that report, Hydro identified separate peer groups for generation KPIs and transmission KPIs and proposed that, subject to data availability, the selected peers remain constant to allow for meaningful trend comparisons over time. This is the sixth year of reporting generation and transmission financial KPI peer data. The list of peers used for KPI benchmarking for Financial Performance Indicators is included as Appendix C. This peer group benchmarking data is sourced from the U.S. Federal Energy Regulatory Commission (FERC) database, to which Hydro has a subscription. All financial data for the U.S.-based peer group is in $US and all financial data for Hydro is in $Cdn.

With respect to the Corporate and Distribution KPIs (items 1 and 5 above), in its 2007 Annual Report on KPIs Hydro had incorporated peer benchmarking data from the Canadian Electricity Association's (CEA) Committee on Performance Excellence (COPE) as published in the "Peer Group Performance Measures for Newfoundland Power" report. However, the CEA has informed Newfoundland Power that the composite information for these measures is no longer available, nor are any other cost-related CEA composite indicators available for benchmarking purposes.[6] As a result, Newfoundland Power is now using a peer group of U.S. companies. This group of US companies is not an appropriate group for Hydro due to Hydro's relatively small distribution component. In order to maintain consistency for year-over-year comparisons, Hydro is using the same peer group of U.S. companies for the Corporate Controllable Unit Cost KPI that Hydro uses for its generation financial benchmarking.

[5] This KPI is not available for benchmarking from 2007 onwards. It will continue to be reported for Hydro for annual comparison purposes. Please see section 3.3.4 a) Distribution Controllable Cost for a discussion of the alternate KPI to be used for peer benchmarking.

[6] "Peer Group Performance Measures for Newfoundland Power", December 23, 2008, p.2.

### 3.3.1 Financial KPI: Corporate

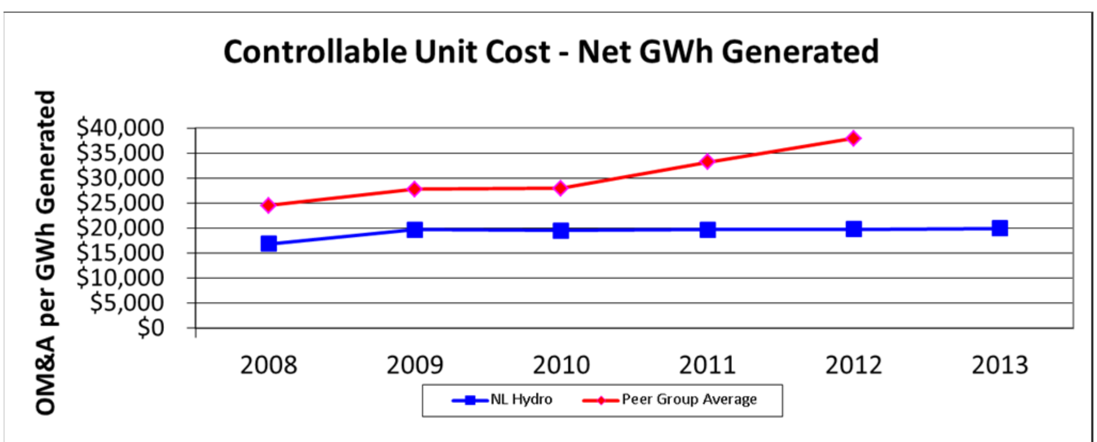
**3.3.1 a) Controllable Unit Cost** - *a high level corporate KPI that tracks Hydro's OM&A expenses in relation to its total energy delivered, expressed as dollars per MW hour. Total Corporate OM&A includes all operating labour and materials for Hydro's generation, transmission, distribution, customer-related and administrative costs, loss on disposal of capital assets. Energy deliveries have been normalized for weather, customer hydrology, and industrial strikes.*

Hydro's OM&A costs increased from $108.7 million in 2012 to $113.8 million[7] in 2013, resulting in a Controllable Unit Cost of $15.53 per MWh delivered for 2013.

Up to 2006, Hydro's Controllable Unit Cost was compared to the average Controllable Unit Cost for participants in the CEA COPE program as reported by Newfoundland Power. As of 2008, however, Newfoundland Power no longer uses CEA COPE benchmarking data for cost-related measures, because the composite information for these measures is no longer available for publication. Peer group results for the period 2007-2012 have therefore been herein restated using the same U.S. Peer Group that Hydro uses for generation financial KPIs.

For computation of Hydro's Corporate Controllable Unit Cost, normalized energy delivered is used. However, the available peer group data from the FERC database is based on net energy generated. Thus, for better comparison against the peer group, Hydro's data will also be calculated and charted on this basis. Hydro's Corporate OM&A per unit of net generation was $19.99 per MWh during 2013, higher than the computed Controllable Unit Cost, because normalized deliveries are higher than net generation due to the effect of Hydro's energy purchases.

Hydro's Corporate Controllable Unit Cost is following a very steady trend as compared to an upward trend for the peer group. However, it is difficult to determine specifically what factors might be impacting the expenses of the peer group participants without detailed information regarding their operations and finances.



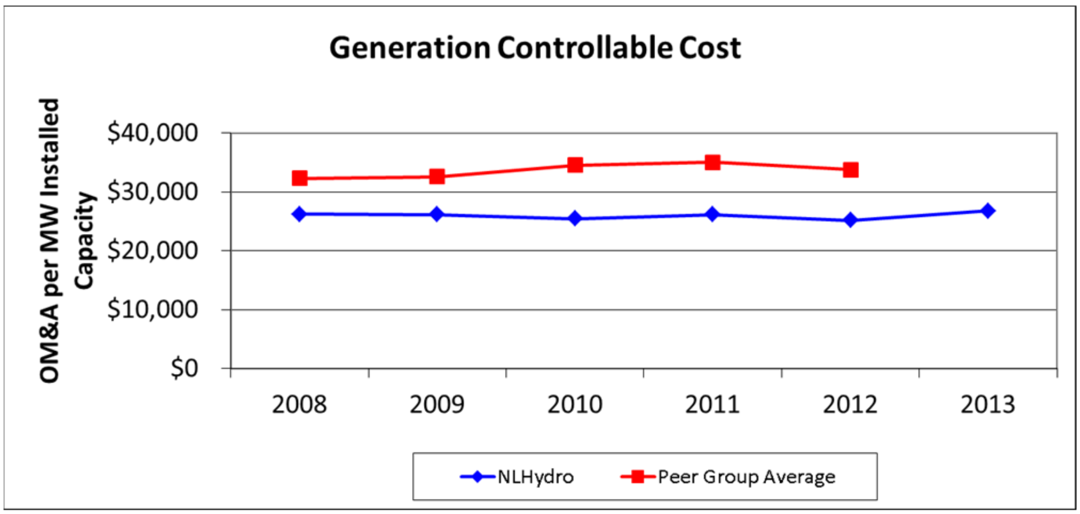

[7] This $113.8 million was calculated in the 2013 Cost of Service study and includes a $2.0 million cost to Hydro that was incurred to service an unregulated Industrial Customer. The $2.0 million was excluded when the $111.8 million regulated amount was reported on the Statement of Income – Regulated Operations for 2013, filed as part of the December 31, 2013 Quarterly Regulatory Report.

### 3.3.2 Financial KPI: Generation

**3.3.2 a) Generation Controllable Cost** - *a functional corporate KPI that tracks Hydro's generation costs in relation to its installed generation. It is computed by dividing generation OM&A by installed capacity as measured in MW.*

Generation Controllable Cost was $26,774 per MW for 2013 compared with $25,131 in 2012 an increase of $1,643 per MW. As mentioned in prior annual KPI reports, an asbestos abatement program was undertaken at Holyrood in 2005 through 2007. Amortization of costs associated with this program concluded during 2012.

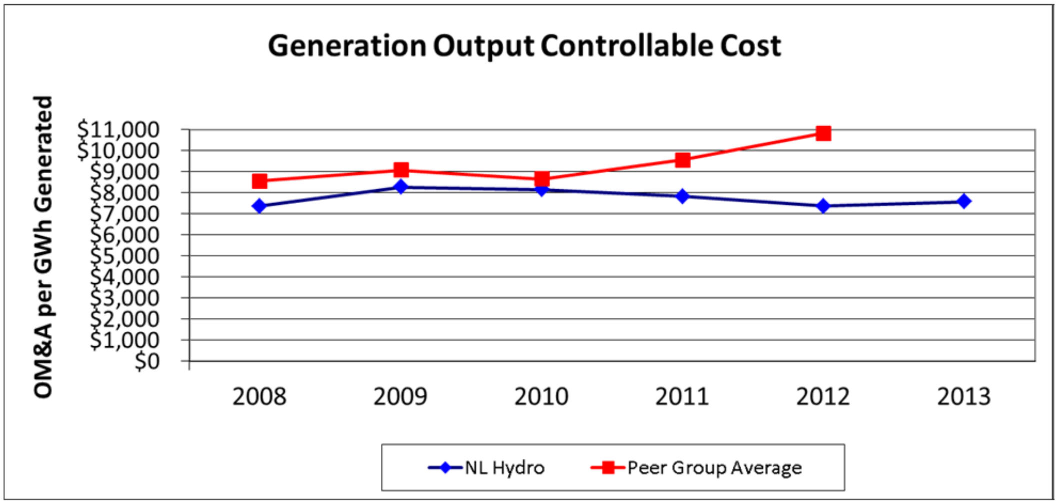
The peer group used to benchmark Generation Controllable Costs appears to be experiencing a slight decrease in OM&A per MW installed capacity while Hydro is showing an increase in 2013.




**3.3.2 b) Generation Output Controllable Cost** - *a functional corporate KPI that tracks Hydro's generation OM&A expenses in relation to its net generation measured in GWh.*

In 2013, Hydro's Generation Output Controllable Cost of $7,568 per GWh, was higher than the $7,358 in 2012. There was an increase in the Generation Costs component of approximately $2.7 million from 2012 to 2013 coupled with an increase of 200 GWh in the Net Energy Generated.

From 2008 through 2010, Hydro's Generation Output Controllable Costs were primarily in line with and trending in a similar direction as those of the peer group with moderate declines for Hydro in 2011 and 2012.

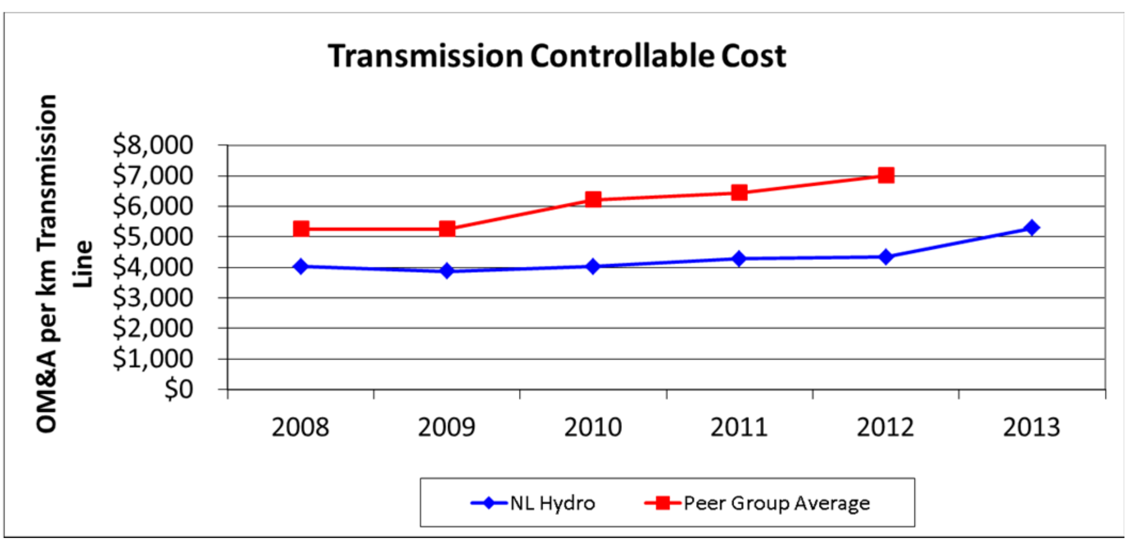



### 3.3.3 Financial KPI: Transmission

**3.3.3 a) Transmission Controllable Cost** - *a KPI that tracks Hydro's transmission OM&A expenses in relation to the 230 kV equivalent length of its transmission circuits (69 kV lines and above).*

In 2013, Hydro's Transmission Controllable Cost was $5,281 per km of transmission, an increase of 21.8% over 2012.

Hydro's costs per km of transmission circuit are trending in a similar pattern as the peer group, although per unit cost increases appear to be increasing at a slower rate within Hydro for the period 2010 to 2012. A direct cost per unit km within the peer group is not meaningful due to differences in accounting and corporate cost allocations; however comparisons over time can highlight relevant trends.



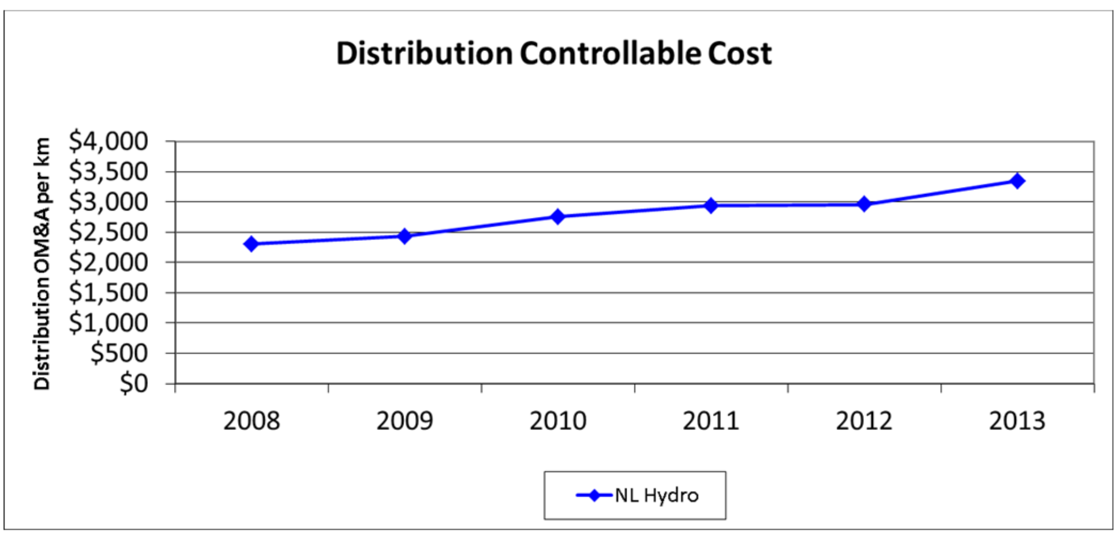
### 3.3.4 Financial KPI: Distribution

**3.3.4 a) Distribution Controllable Cost** - *a functional corporate KPI that tracks Hydro's distribution OM&A expenses in relation to the length of its equivalent 230 kV distribution circuits in kilometres*[8].

The Distribution Controllable Cost KPI had previously been reported as dollars per km of distribution using the CEA COPE data. As discussed, the CEA COPE data is no longer available for benchmarking of financial KPIs. Additionally, although distribution cost data is available for the U.S.-based peer group used by Hydro for Transmission Controllable Cost, the associated km of distribution data is unavailable. In the absence of the CEA COPE data, Newfoundland Power has chosen to use a KPI that divides total Distribution OM&A by MWh of retail sales. Hydro will therefore use this same data set. However, given Hydro's relatively small quantity of retail sales, combined with the rural and remote locations of these sales, it is expected that Hydro's Distribution cost per MWh will be significantly higher than Newfoundland Power's and the peer group average.

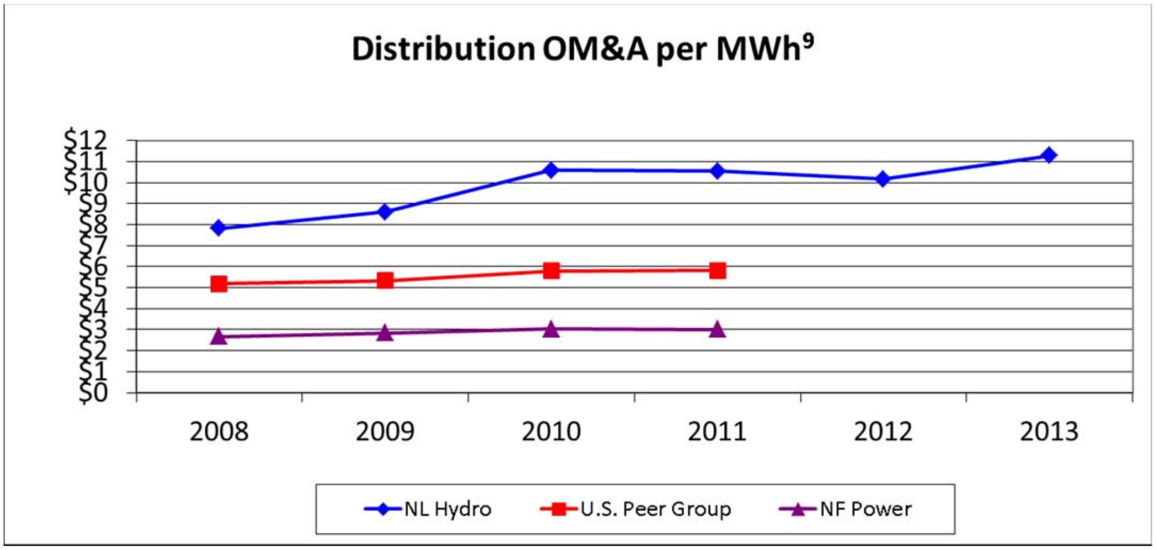
The distribution cost per km of circuit length will continue to be reported for year-over-year trend analysis.

At $3,345 per circuit km Hydro's Distribution Controllable Cost of 2013 increased from the $2,960 that was recorded in 2012. This is in line with the upward trend in this cost that was seen between 2008 and 2012.




As expected, Hydro's distribution costs of $11.27 in 2013 trend higher than those of its peers in the table below. The distribution systems are a relatively small component of Hydro's total plant compared to generation and transmission plant and also compared to Newfoundland Power's distribution assets. Thus, Hydro's higher costs per MWh are likely due to the rural and geographically dispersed nature of its distribution systems and the resultant inability to achieve cost economies.

[8] CEA COPE peer data used up to 2007 excluded circuits less than 1 kV. Hydro's data has also been adjusted to exclude circuits less than 1 kV from 2003 onward.




## *3.4 Customer-Related Performance Indicators*

**3.4.1 a) Residential Customer Satisfaction** - *an indicator of Hydro's residential customers overall satisfaction level with service, which is tracked by the Percent Satisfied Customers KPI[10].*

*The Percent Satisfied Customers measure is also a corporate performance KPI that tracks the satisfaction of rural residential customers with Hydro's performance. The Percent Satisfied Customers measure is produced via an annual survey of Hydro's residential customers.*

There was no customer survey completed in 2013.

[9] The 2012 Distribution OM&A per MWh data for NF Power and U.S Peer Group are currently not available.
[10] As of 2009, the Customer Satisfaction index (CSI) is no longer being calculated as a Customer-Related Performance Indicator.

# 4 Data Table of Key Performance Indicators

Key Performance Indicators' targets for 2014 were established in the same manner as in previous years. Any future changes in methodology will be included as soon as a change occurs.

**Updated May 2014**

**Newfoundland and Labrador Hydro**
**Key Performance Indicators (KPI)**
**Results for 2013 plus Targets/Budgets for 2014[1]**

| KPI | Measure Definition | Units | 2009 | 2010 | 2011 | 2012 | 2013 | 2014T Target |
|---|---|---|---|---|---|---|---|---|
| **Reliability** | | | | | | | | |
| **Generation** | | | | | | | | |
| Weighted Capability Factor[2] | Availibility of Units for Supply | % | 82.0 | 83.4 | 83.3 | 82.9 | 75.5 | 83.8 |
| Weighted DAFOR[2] | Unavailibility of Units due to Forced Outage | % | 4.5 | 1.8 | 2.7 | 2.3 | 12.2 | 2.67 |
| **Transmission[6,]** | | | | | | | | |
| T-SAIDI | Outage Duration per Delivery Point | Minutes / Point | 100 | 173 | 432 | 171 | 468.5 | 180 |
| T-SAIFI | Number of Outages per Delivery Point | Number / Point | 0.9 | 2.3 | 4.5 | 1.9 | 3.5 | 1.58 |
| T-SARI | Outage Duration per Interuption | Minutes / Outage | 111 | 75 | 96 | 90 | 133.9 | 113.92 |
| **Distribution** | | | | | | | | |
| SAIDI | Average Outage Duration for Customers | Hours / Customer | 9.4 | 6.6 | 16.3 | 8.3 | 18.6 | 5.9 |
| SAIFI | Number of Outages for Customers | Number / Customer | 4.3 | 3.5 | 5.7 | 4.4 | 5.7 | 3.65 |
| **Under Frequency Load Shedding** | | | | | | | | |
| UFLS | Customer Load Interruptions Due to Generator Trip | Number of Events | 7 | 6 | 3 | 5 | 7 | 6 |
| **Operating** | | | | | | | | |
| Hydraulic Conversion Factor[3] | Net Generation / 1 Million $m^3$ Water | GWh / MCM | 0.434 | 0.436 | 0.434 | 0.434 | 0.432 | 0.433 |
| Thermal Conversion Factor[4] | Net kWh / Barrel No. 6 HFO | kWh / BBL | 612 | 589 | 603 | 599 | 595 | 615 |
| **Financial (Regulated)** | | | | | | | | |
| Controllable Unit Cost[5] | Controllable OM&A$ / Energy Deliveries | $/MWh | $14.91 | $14.25 | $14.96 | $14.93 | $15.53 | N/A[8] |
| Generation Controllable Costs | Generation OM&A$ / Installed MW | $ / MW | $26,138 | $25,465 | $26,169 | $25,131 | $26,774 | N/A[8] |
| | Generation OM&A$ / Net Generation | $ / GWh | $8,267 | $8,159 | $7,833 | $7,358 | $7,568 | N/A[8] |
| Transmission Controllable Costs | Transmission OM&A$ / 230 kV Eqv Circuit Km | $ / Km | $3,870 | $4,021 | $4,275 | $4,335 | $5,281 | N/A[8] |
| Distribution Controllable Costs | Distribution OM&A$ / Circuit Km | $ / Km | $2,429 | $2,755 | $2,934 | $2,960 | $3,343 | N/A[8] |
| **Other** | | | | | | | | |
| Percent Satisfied Customers[7] (Residential) | Satisfaction Rating | Max = 100% | 91% | 92% | 88% | 80% | N/A | 80% |

Notes:
1. Historical data has been updated and/or corrected where applicable.
2. The 2012 targets for weighted capability factor and DAFOR are based on the annual generation outage schedule.
3. For the Bay d'Espoir hydroelectric plant.
4. For the Holyrood thermal plant.
5. Energy deliveries have been normalized for weather, customer hydrology, and industrial strikes. No adjustments have been made for AC Stephenville mill closure.
6. The 2012 targets for T-SAIFI and T-SAIDI are based on the combination of forced and planned outage performance.
7. There was no customer satisfaction survey completed for 2013.
8. Not appliable

# *Appendices*

## Appendix A: Rationale for Hydro's 2013 KPI Targets

| KPI | Comment on KPI 2013 Target |
|---|---|
| Reliability | Hydro has adopted a target setting approach wherein known factors that affect reliability performance are incorporated into the target setting process wherever practical. This approach also uses percentage improvements and past performance levels to set target levels for continuous improvements. |
| Weighted Capability Factor | The 2013 target is set using the expected annual generation unit outage schedule combined with performance improvements relative to recent history. |
| Weighted DAFOR | The 2013 target is set using the expected annual generation unit outage schedule combined with performance improvements relative to recent history. |
| Transmission SAIDI, SAIFI, and SARI | The 2013 targets for forced outage performance are set based upon recent performance improvements. The planned outage contribution to total performance is set using the annual transmission terminals maintenance outage plan. |
| Distribution SAIDI & SAIFI | Improvements relative to the most recent five-year average. |
| Underfrequency Load Shedding | The 2013 target is based upon improvement over the most recent five-year average. |
| **Operating** | |
| Hydraulic Conversion Factor | Hold at the previous target value. |
| Thermal Conversion Factor | The 2013 target is based on November 2012 budget for 2013 Holyrood plant operation. |
| **Other** | |
| Customer Satisfaction | Targeting continuous improvement. |

## Appendix B: Computation of Weighted Capability Factor and Factors Impacting Performance

Weighted Capability Factor is calculated using the following formula:

$$1-\frac{\sum_{all\ units}\left(\frac{unit\ total\ equivalent\ outage\ time \times unit\ MCR}{unit\ hours}\right)}{\sum_{all\ units} unit\ MCR}$$

Where,

**MCR** = Maximum Continuous Rating, the gross maximum electrical output, measured in megawatts, for which a generating unit has been designed and/or has been shown capable of producing continuously. MCR would only change if the generating capability of a unit is permanently altered by virtue of equipment age, regulation, or capital modifications. Such changes to MCR are infrequent and have not actually taken place within Hydro since the 1980's when two units at Holyrood were uprated due to modifications made to these units.

**Unit hours** = the sum of hours that a unit is in commercial service. This measure includes time that a unit is operating, shut down, on maintenance, or operating under some form of derating. Unit hours will only be altered in the infrequent event that a unit is removed from commercial service for an extended period of time.

**Unit total equivalent outage time** = the period of time a unit is wholly or partially unavailable to generate at its MCR. For the purposes of calculating outage time, the degree to which a unit is derated is converted to an outage equivalency. Thus, a unit that is able to generate at 75% load for four days would have an equivalent outage time of one full day out of four. Factors that can affect unit total equivalent outage time are classified by CEA under nine categories, which are outlined in Appendix A to this Report. Hydro tracks the time that each unit spends in each of these nine states and calculates the weighted capability accordingly.

Unit total equivalent outage time is the measure that is most likely to impact Weighted Capability Factor on a year-to-year basis, since MCR and unit hours are unlikely to change.

# Appendix B: Computation of Weighted Capability Factor and Factors Impacting Performance (Cont'd)

**Factors that Affect Unit Total Equivalent Outage Time**

1. **Sudden Forced Outage.** An occurrence wherein a unit trips or becomes immediately unavailable.
2. **Immediately Deferrable Forced Outage**. An occurrence wherein a unit must be made unavailable within a very short time (10 minutes).
3. **Deferrable Forced Outage**. An occurrence or condition wherein a unit must be made unavailable within the next week.
4. **Starting Failure**. A condition wherein a unit is unable to start.
5. **Planned Outage**. A condition where a unit is unavailable because it is on its annual inspection and maintenance.
6. **Maintenance Outage**. A condition where a unit is unavailable due to repair work. Maintenance outage time covers outages that can be deferred longer than a week, but cannot wait until the next annual planned maintenance period.
7. **Forced Derating**. A condition that limits the usable capacity of a unit to something less than MCR. The derating is forced in nature, typically because of the breakdown of a subsystem on the unit.
8. **Scheduled Derating**. A condition that limits the usable capacity of a unit to something less than MCR, but is done by virtue of the decision of the unit operator. Scheduled deratings are less common than forced deratings, but can arise, for example, when a unit at Holyrood is derated to remove a pump from service.
9. **Common Mode Outages**. Common mode outages are rare, and arise when an event causes multiple units to become unavailable. An example might be the operation of multiple circuit breakers in a switchyard at Holyrood due to a lightning strike, rendering up to three units unavailable.

Note: There are hundreds of CEA equipment codes for generator subsystems that track the cause for the time spent in each of the above categories.

# Appendix C1: Significant Transmission Events – 2013

There were eight significant events in 2013. The details follow:

## Event 1

On January 11, there was a major system event affecting delivery points in all regions of the Island Interconnected System. It is summarized as follows:

A severe winter blizzard resulted in island wide power outages and significant customer impact. The events started early in the morning at the Holyrood Terminal Station, where the high winds and heavy, salt contaminated, snow created electrical faults and significant disturbances by 0648 hours. There was a loss of all three generating units at the Holyrood Thermal Generating Station and trips and lockouts of the 138 kV and 230 kV busses. This effectively isolated the Holyrood generating and terminal stations from the remainder of the grid. There was a significant customer impact, primarily to customers on the Avalon Peninsula. The station service supply into the plant was interrupted and could not be re-established until personnel arrived at site to reset lockout relays. This occurred at approximately 1500 hours. Unit 1 required a major refurbishment and repairs. It was released for service in early October.

Approximately one hour (0742 hours) following the loss of the Holyrood generating and terminal stations, there was a trip of the only remaining 230 kV transmission line from Western Avalon to the major load centers in St. John's and surrounding area. With the separation of the east/west power systems and loss of supply to the eastern Avalon, there was severe instability in the central and western areas, resulting in the loss of multiple generating stations and transmission lines. The customer impact had then spread to be island wide with only a few smaller regions still with power.

The line from Western Avalon tripped again approximately one hour and ten minutes later (0851 hours), resulting in additional customer outages and reversing much of the restoration effort that had taken place up to that time.

The following table outlines the delivery point customer interruptions.

# Appendix C1: Significant Transmission Events – 2013 (Cont'd)

Events on January 11, 2013

| Delivery Point Affected | Start Time | Finish Time | Duration of Interruptions (mins) | MW Load | MW-Mins |
|---|---|---|---|---|---|
| Deer Lake Power - TL225 | 1/11/2013 7:43 | 1/11/2013 11:52 | 249.00 | 0.00 | 0.00 |
| Deer Lake - NP | 1/11/2013 7:43 | 1/11/2013 11:43 | 240.00 | 12.67 | 3,040.80 |
| Port Aux Basques | 1/11/2013 7:43 | 1/11/2013 11:20 | 217.00 | 15.74 | 3,415.58 |
| Doyles | 1/11/2013 7:43 | 1/11/2013 11:20 | 217.00 | 3.94 | 854.98 |
| Grandy Brook | 1/11/2013 7:43 | 1/11/2013 12:07 | 264.00 | 3.70 | 976.80 |
| Bottom Brook - 400L | 1/11/2013 7:43 | 1/11/2013 12:07 | 171.00 | 0.00 | 0.00 |
| Stephenville | 1/11/2013 7:43 | 1/11/2013 10:34 | 171.00 | 34.37 | 5,877.27 |
| Massey Drive Bus B3 (1) | 1/11/2013 7:43 | 1/11/2013 8:01 | 18.00 | 65.26 | 1,174.68 |
| Massey Drive Bus B3 (2) | 1/11/2013 8:10 | 1/11/2013 9:45 | 95.00 | 34.62 | 3,288.90 |
| Massey Drive Bus B3 (3) | 1/11/2013 7:43 | 1/11/2013 9:45 | 122.00 | 30.64 | 3,738.08 |
| Massey Drive Bus B4 | 1/11/2013 7:43 | 1/11/2013 11:58 | 255.00 | 35.46 | 9,042.30 |
| Wiltondale (1) | 1/11/2013 7:43 | 1/11/2013 9:19 | 96.00 | 0.11 | 10.23 |
| Glenburine (1) | 1/11/2013 7:43 | 1/11/2013 9:19 | 96.00 | 2.13 | 204.67 |
| Rocky Harbour (1) | 1/11/2013 7:43 | 1/11/2013 9:19 | 96.00 | 3.09 | 296.77 |
| Wiltondale (2) | 1/11/2013 9:40 | 1/11/2013 9:47 | 7.00 | 0.05 | 0.36 |
| Glenburine (2) | 1/11/2013 9:40 | 1/11/2013 9:47 | 7.00 | 1.03 | 7.20 |
| Rocky Harbour (2) | 1/11/2013 9:40 | 1/11/2013 9:47 | 7.00 | 1.49 | 10.43 |
| South Brook | 1/11/2013 7:43 | 1/11/2013 7:48 | 5.00 | 3.79 | 18.95 |
| Duck Pond Mine | 1/11/2013 7:43 | 1/11/2013 23:59 | 976.00 | 8.57 | 8,364.32 |
| St. Anthony | 1/11/2013 8:01 | 1/11/2013 8:32 | 31.00 | 7.31 | 226.61 |
| Roddickton | 1/11/2013 8:01 | 1/11/2013 8:30 | 29.00 | 1.66 | 48.14 |
| Cobb's Pond | 1/11/2013 7:43 | 1/11/2013 9:12 | 89.00 | 60.00 | 5,340.00 |
| Farewell Head | 1/11/2013 7:43 | 1/11/2013 9:12 | 89.00 | 3.00 | 267.00 |
| Glenwood | 1/11/2013 7:43 | 1/11/2013 9:12 | 89.00 | 3.00 | 267.00 |
| Grand Falls | 1/11/2013 7:43 | 1/11/2013 10:03 | 140.00 | 60.00 | 8,400.00 |
| Sunnyside - 100L | 1/11/2013 7:43 | 1/11/2013 9:03 | 80.00 | 10.25 | 820.00 |
| Sunnyside - 109L | 1/11/2013 7:43 | 1/11/2013 9:03 | 80.00 | 11.81 | 944.80 |
| Holyrood - 39L | 1/11/2013 6:42 | 1/11/2013 6:43 | 1.00 | 0.00 | 0.00 |
| Hardwoods (1) | 1/11/2013 7:43 | 1/11/2013 8:00 | 17.00 | 159.72 | 2,715.24 |
| Hardwoods (2) | 1/11/2013 8:51 | 1/11/2013 9:14 | 23.00 | 108.09 | 2,486.07 |
| Oxen Pond (1) | 1/11/2013 6:48 | 1/11/2013 7:11 | 23.00 | 171.00 | 3,933.00 |
| Oxen Pond (2) | 1/11/2013 7:43 | 1/11/2013 8:03 | 20.00 | 115.49 | 2,309.80 |
| Oxen Pond (3) | 1/11/2013 8:51 | 1/11/2013 9:31 | 40.00 | 110.88 | 4,435.20 |
| | | **Totals** | 4,020.00 | 967.99 | 72,515.19 |

**(Unsupplied Energy: 72,515 MW-Mins)**

## Event 2

On February 4, North Atlantic Refining Limited (NARL) at Come by Chance, experienced an unplanned power outage of four hours and 26 minutes. The outage occurred when protection relays operated and locked out Bus 1 and Bus 2 at the Come By Chance Terminal Station, isolating NARL from the system grid. The bus protection relays tripped transmission lines TL-207 at the Sunnyside Terminal Station and TL-237 at the Western Avalon Terminal Station. The cause of the outage was plastic debris coming in contact with high voltage equipment during high winds on that day, and the failure of a component (blocking diode) in the protection circuit that caused a misoperation of the 230 kV bus lockout, tripping the bus tie breaker B1B2.

Following the incident, an investigation determined a revised design to eliminate the use of blocking diodes in the Come By Chance breaker failure circuits. The breaker failure protection was upgraded with the revised design on February 28. (**Unsupplied Energy: 7,336 MW-Mins)**

## Event 3

On February 10, Newfoundland Power customers in the Sunnyside, Clarenville, Bonavista Peninsula, and the Burin Peninsula areas experienced an unplanned power outage of up to four hours. The outage occurred when the 230 kV Bus 1, at the Sunnyside Terminal Station, experienced a bus protection lockout. It was determined that ice falling from overhead lines fell on substation equipment causing the protection relays to operate. Customers were restored after the bus lockout was reset at 1304 hours. Attempts by Newfoundland Power to restore customers using generation on the Burin Peninsula failed.
(**Unsupplied Energy: 17,523 MW-Mins)**

## Event 4

Starting on February 17 and continuing until February 18, customers on the Great Northern Peninsula experienced three unplanned power outages; refer to the tables below for the customer impact. The outages were caused by high winds causing a structure failure on TL-259 and a transformer lockout on T1 at Berry Hill.

| Delivery Point Affected | Date of Incident | Time of Incident | Time of Restoration | Outage Duration (mins) | Load Loss (MW) | MW-Mins |
|---|---|---|---|---|---|---|
| Cow Head | 2/17/2013 | 16:07 | 16:22 | 14 | 1.2 | 16.80 |
| Parson's Pond | 2/17/2013 | 16:07 | 16:13 | 5 | 0.6 | 3.20 |
| Daniel's Harbour | 2/17/2013 | 16:07 | 16:13 | 5 | 0.8 | 3.75 |
| Hawke's Bay | 2/17/2013 | 16:07 | 16:50 | 42 | 4.5 | 189.00 |
| Plum Point | 2/17/2013 | 16:07 | 16:13 | 5 | 2.3 | 11.50 |
| Bear Cove | 2/17/2013 | 16:07 | 16:13 | 5 | 3.5 | 17.50 |
| Main Brook | 2/17/2013 | 16:07 | 16:17 | 9 | 0.5 | 4.68 |
| Roddickton | 2/17/2013 | 16:07 | 16:17 | 9 | 1.3 | 11.70 |
| St. Anthony | 2/17/2013 | 16:07 | 16:17 | 9 | 7.5 | 67.50 |
| Wiltondale | 2/17/2013 | 16:24 | 16:32 | 7 | 0.3 | 2.10 |
| Glenburine | 2/17/2013 | 16:24 | 16:32 | 7 | 5.9 | 41.30 |
| Rocky Harbour | 2/17/2013 | 16:24 | 16:32 | 7 | 8.4 | 58.80 |
| Cow Head | 2/17/2013 | 16:24 | 17:04 | 39 | 1.8 | 70.20 |
| Wiltondale | 2/17/2013 | 17:53 | 17:54 | 1 | 0.1 | 0.10 |
| Glenburine | 2/17/2013 | 17:53 | 17:54 | 1 | 2.3 | 2.30 |
| Rocky Harbour | 2/17/2013 | 17:53 | 17:54 | 1 | 3.3 | 3.30 |
| Cow Head | 2/17/2013 - 2/18/2013 | 17:53 | 2:15 | 501 | 2.0 | 1002.00 |

**(Unsupplied Energy: 1,506 MW-Mins)**

## Event 5

On March 22, customers supplied by the Conne River, English Harbour West, and Barachoix Terminal Stations experienced an unplanned power outage of four hours and 44 minutes. (284 mins). The outage occurred after transmission line TL220 was removed from service due to arcing on disconnect switch L20-1 at Conne River. The switch was repaired before TL220 was returned to service.
(**Unsupplied Energy: 2,442 MW-Mins)**

# Appendix C1: Significant Transmission Events – 2013 (Cont'd)

## Event 6

On June 14, customers supplied by the Happy Valley Terminal Station and the Muskrat Falls Tap Terminal Station experienced an unplanned power outage of two hours and 40 minutes. The outage occurred after lightning hit transmission line L1301/L1302. There was a delay in the restoration of customers due to an issue with the overvoltage protection setting at the Muskrat Falls Tap Terminal Station. There were protection settings changes implemented following this event.
(**Unsupplied Energy: 3,424 MW-Mins)**

## Event 7

On June 22, customers supplied by the Happy Valley Terminal Station and Nalcor Energy at Muskrat Falls Tap Terminal Station experienced an unplanned power outage of one hour and eight minutes. The outage occurred after lightning hit transmission line L1301/L1302. There was delay in the restoration of customers due to an issue with low air pressure at the circuit breaker at the Churchill Falls end of L1301.
(**Unsupplied Energy: 1,176 MW-Mins)**

## Event 8

On November 28, all customers on the Great Northern Peninsula, experiencing a series of unplanned power outages, see the following table. The outages were caused by a damaged insulator on TL227, a broken jumper on TL227 and a transformer lockout on T1 at Berry Hill.

# Appendix C1: Significant Transmission Events – 2013 (Cont'd)

Events on November 28, 2013

| Delivery Point Affected | Start Time | Finish Time | Duration of Interruptions (mins) | MW Load | MW-Mins |
|---|---|---|---|---|---|
| | | | | | |
| Cow Head | 4:56:00 | 4:56:00 | 0 | 0.7 | 0.00 |
| Parson's Pond | 4:57:00 | 7:16:00 | 139 | 0.3 | 34.75 |
| Daniel's Harbour | 4:57:00 | 7:16:00 | 139 | 0.5 | 73.67 |
| Hawke's Bay | 4:57:00 | 6:13:00 | 76 | 2.7 | 202.92 |
| Plum Point | 4:57:00 | 7:19:00 | 142 | 1.6 | 225.78 |
| Bear Cove | 4:57:00 | 7:21:00 | 144 | 2.4 | 345.60 |
| Main Brook | 4:57:00 | 7:31:00 | 154 | 0.2 | 36.96 |
| Roddickton | 4:57:00 | 7:31:00 | 154 | 1.1 | 170.94 |
| St. Anthony Total | 4:57:00 | 6:52:00 | 115 | 5.1 | 586.50 |
| St. Anthony Line 1 | 4:57:00 | 6:35:00 | 98 | 1.4 | 137.20 |
| St. Anthony Line 2 | 4:57:00 | 6:52:00 | 115 | 1.1 | 126.50 |
| St. Anthony Line 3 | 4:57:00 | 6:21:00 | 84 | 2.5 | 210.00 |
| Wiltondale | 5:16:00 | 5:19:00 | 3 | 0.1 | 0.30 |
| Glenburnie | 5:16:00 | 5:19:00 | 3 | 1.3 | 3.90 |
| Rocky Harbour | 5:16:00 | 5:19:00 | 3 | 1.9 | 5.70 |
| Wiltondale | 5:22:00 | 5:26:00 | 4 | 0.1 | 0.40 |
| Glenburnie | 5:22:00 | 5:26:00 | 4 | 1.4 | 5.60 |
| Rocky Harbour | 5:22:00 | 5:26:00 | 4 | 2.0 | 8.00 |
| Hawke's Bay Line 1 | 6:17:00 | 6:34:00 | 17 | 1.1 | 18.70 |
| Cow Head | 4:57:00 | 9:15:00 | 258 | 0.6 | 154.80 |
| St. Anthony Total | 8:53:00 | 8:58:00 | 5 | 8.4 | 42.00 |
| St. Anthony Line 1 | 8:53:00 | 8:57:00 | 4 | 2.1 | 8.40 |
| St. Anthony Line 2 | 8:53:00 | 8:57:00 | 4 | 1.8 | 7.50 |
| St. Anthony Line 3 | 8:53:00 | 8:58:00 | 5 | 3.8 | 19.00 |
| Cow Head | 10:17:00 | 16:50:00 | 393 | 1.0 | 393.00 |
| Parson's Pond | 10:37:00 | 16:39:00 | 362 | 0.4 | 144.80 |
| | | **Totals** | 2,429 | 45.60 | 2,334.12 |

**(Unsupplied Energy: 2,334 MW-Mins)**

## Appendix C2: Significant Distribution Events – 2013 (Excluding Fourth Quarter)

- On January 18, customers serviced by Lines 3, 7, 8, 9, 11, and 12 in Wabush experienced an unplanned power outage. The outage occurred due to an overload on the 46 kV line supplying the Wabush distribution system. The outage duration was up to three hours for some customers.

- On February 27, 373 customers serviced by Line 11 in Labrador City experienced an unplanned power outage of three hours in duration. Hydro crews investigated the outage and found a dead crow in the Quartzite substation.

- On March 4 at 1858 hours, 1,010 customers supplied by Line 16 in Happy Valley-Goose Bay experienced an unplanned power outage. The outage occurred when the line recloser tripped due to a broken utility pole. Hydro crews completed repairs and the first attempt to restore these customers occurred at 2227. The recloser tripped again at 2229, with the cause suspected to be an overload on the line due to cold load pickup. Following this trip there were numerous, unsuccessful attempts to restore customers on Line 16. On three occasions, at 2241, 2310 and at 0045 hours, the attempts resulted in trips of the station transformers (T1 and T2) and an outage to all customers (4,919) supplied by the HVGB station, of durations three, 15 and 8 minutes, respectively.

- By 0350 on March 5, Line 16 had been sectionalized and some of the customers supplied by this line were restored. At 0437 however, the station transformers (T1 and T2) tripped again resulting in another outage to all customers supplied by the HVGB station, of three minutes in duration. All customers on Line 16 (excluding those on Feeder 9) were restored again by 0513. Customers on Feeder 9 were restored at 0545 hours. After further investigation, it was determined that the issues in restoring Line 16 were due to a severe feeder unbalance and operation of a back-up overcurrent relay which is wired to trip the transformer breakers. There were several action items arising from these events.

- On March 22, at 2100 hours (Labrador time), 825 customers served by feeder L7 in the town of Happy Valley-Goose Bay experienced an unplanned power outage. The outage was caused by a tree contacting the feeder and breaking the primary conductor. The tree was removed, the conductor was repaired and all customers were restored at 0000 hours (midnight on March 23).

- On March 24, starting at 0610 hours (Labrador time), 804 customers in the towns of Happy Valley-Goose Bay and Mud Lake experienced a planned power outage. The outage was required to reduce the local generation requirements of the Happy Valley gas turbine for a planned outage on transmission line L1301. Line L1301 was removed from service to safely interconnect a new terminal station for construction power for Muskrat Falls. The following table outlines the customer outage durations:

| Date | Asset | Time of Incident | Time of Restoration | Outage Duration | Number of Customers |
|---|---|---|---|---|---|
| Mar 24 | Line 5 | 0630 | 1508 | 8 hrs and 38 mins | 363 |
| Mar 24 | Line 6 | 0610 | 1515 | 9 hrs and 5 mins. | 428 |
| Mar 24 | Line 17 | 0610 | 1515 | 9 hrs and 5 mins. | 13 |

- Thirty customers in Mud Lake experienced an additional unplanned outage at 1515 hours following attempts to restore feeder L6. A tree had contacted the feeder during the planned outage earlier in the day. The tree was removed and these customers were restored at 1630 hours.

- On April 6, beginning at 0845 hours, all customers (1,541) on Fogo Island experienced a series of lengthy unplanned power outages. All customers were restored by 1100 hours on April 07. Hydro's investigation concluded the cause of the outages was a defective insulator on Line 1. Crews were dispatched to locate the cause and once discovered, the defective insulator was replaced. Weather at the time of the incident was poor and resulted in delays in restoration.

- On April 8, all customers (1,048) serviced by South Brook Lines 3, 5, 7 experienced an unplanned power outage of up to eight hours and 30 minutes. The outage was caused the failure of a connector that resulted in a pole fire. The pole fire caused damage to the pole and the crossarm. Both the pole and the crossarm were replaced. Customers on Line 3 and Line 7 experienced an outage duration of four hours and 35 minutes.

- On April 8, all customers (841) serviced by Bottom Waters Lines 3, 6, 7 experienced an unplanned power outage of up to six hours and 50 minutes. The outage was caused by a faulty voltage regulator (BW3-VR1). The regulator was removed from service to restore customers and was later replaced. The outage durations were as follows:

  Line 3: five hours 45 minutes
  Line 6: six hours 50 minutes
  Line 7: six hours 15 minutes

- On April 25, at 1800 hours (Labrador time), 40 customers serviced by Line 5 in Labrador City experienced an unplanned power outage. The outage was caused by a broken porcelain cut-out. In order to safely repair the cut-out, an emergency planned power outage was required for Line 5, affecting an additional 214 customers. Hydro crews repaired the cut-out and all customers were restored at 1920 hours.

- On May 14, all customers (1,606) on Fogo Island experienced an unplanned power outage. The outage occurred when a lightning arrester failed at the submarine cable termination station. Hydro crews repaired the problem and all customers were restored during the morning hours on May 15. Total outage time was eight hours and 46 minutes.

- On July 2, all customers (31) serviced by Charlottetown, Labrador Line 2 experienced an unplanned power outage of 12 hours and 45 minutes. The outage occurred after a lightning strike damaged a distribution pole.

- On July 3, all customers (282) serviced by Plum Point Line 2 experienced a planned power outage of 4 hours and 56 minutes. The outage was required to complete upgrades on the distribution system.

- On July 16, all customers (97) serviced by King's Point Line 2 experienced an unplanned power outage of 11 hours and 36 minutes. The outage occurred after a forest fire damaged two distribution poles and a pole-top transformer. The poles and transformer were replaced.

- On August 10, all customers (265) serviced by the diesel plant in Hopedale, Labrador experienced an unplanned power outage of 7 hours and 35 minutes. The outage occurred after diesel Unit 2053 shut down due to an issue with its rotor. Hydro's onsite Diesel Representative tried unsuccessfully to restore customers with Units 2054 and 2074. A maintenance crew was required to travel from Happy Valley-Goose Bay to the site to replace a starter on Unit 2074 and replace fuses for the station service feed. Customers were restored using Units 2054 and 2074.

- On September 8, all customers (5,630) serviced by the Wabush Terminal Station in the towns of Labrador City and Wabush experienced a planned power outage of up to 11 hours and 45 minutes. This outage was required safely perform maintenance on equipment in the Wabush Terminal Station.

## Appendix C3: Underfrequency Load Shedding Events (Excluding Fourth Quarter)

- On January 16, Holyrood Generating Unit 3 tripped. The cause of the trip was a result of a vacuum trip alarm. It is suspected the alarm was falsely initiated via a faulty relay or a trip switch. The suspected relay has since been replaced and the trip switches have been calibrated and tested. With the removal of generation (approximately 121 MW) the system frequency dropped to 58.4 Hz resulting in the activation of the underfrequency protection at Hydro and Newfoundland Power. Total system load at the time of the incident was 1,024 MW. There were 2,199 Hydro customers restored three minutes after the event occurred (23 MW-Mins). There were 15,299 Newfoundland Power customers reported to be restored within thirteen minutes after the event occurred (Unsupplied Energy: 960 MW-Mins).

- On January 18, Bay d'Espoir Generating Unit 4 tripped. Personnel investigated and determined that the cause of the trip of Unit #4 was a shorted and grounded current transformer (CT) associated with the generator. The CT was replaced and the unit was released for service on January 20 at 0300 hours. With the removal of generation (approximately 68 MW) the system frequency dropped below 58.8 Hz resulting in the activation of the underfrequency protection at Newfoundland Power. Total system load at the time of the incident was 1,312 MW. There were 4,309 Newfoundland Power customers reported to be restored within fifteen minutes after the event occurred (Unsupplied Energy: 270 MW-Mins).

- On March 1, Bay d'Espoir Generating Unit 1 tripped. Hydro's investigation determined that the exciter processor had malfunctioned. The exciter processor was replaced and Unit 1 was available and synched online at 1354 hours on March 2. With the removal of generation (approximately 52 MW) the system frequency dropped below 58.8 Hz resulting in the activation of the underfrequency protection at Newfoundland Power. Total system load at the time of the incident was 836 MW. There were 6,256 Newfoundland Power customers reported to be restored within five minutes after the event occurred (Unsupplied Energy: 115 MW-Mins).

- On March 10, Holyrood Generating Unit 3 tripped. The cause of the unit trip was attributed to a problem with the fuel oil pump. Personnel corrected the issue and the unit was restored to service on March 11 at 0005 hours. With the removal of generation (approximately 69 MW) the system frequency dropped to 58.78 Hz resulting in the activation of the underfrequency protection at Newfoundland Power. Total system load at the time of the incident was 968 MW. There were 6,041 Newfoundland Power customers reported to be restored within eleven minutes after the event occurred (Unsupplied Energy: 220 MW-Mins).

- On April 16 at 1135 hours, Holyrood Generating Unit #2 tripped. The cause of the unit trip was attributed to a malfunction of a pistol grip switch which it is used to place the lube oil pumps in and out of service. With the removal of generation (approximately 91 MW) the system frequency dropped to 58.57 Hz resulting in the activation of the underfrequency protection at Hydro and Newfoundland Power. Total system load at the time of the incident was 901 MW. There were 14,430 Newfoundland Power customers reported to be restored within twenty two minutes after the event occurred. (Unsupplied Energy: 385 MW-Mins) There were 1,281 Hydro customers restored within three minutes after the event occurred. (Unsupplied Energy: 15 MW-Mins)

## Appendix C3: Underfrequency Load Shedding Events (Excluding Fourth Quarter) (cont'd)

- On April 17 at 0700 hours, Bay d'Espoir Terminal Station experienced a 230 kV bus lockout, tripping Units 3 and 5 in addition to making Units 4 and 6 and transmission line TL202 unavailable to the system. The lockout operation was initiated when Unit #4 was being placed online and its unit breaker B2T4 was forced close due to loss of air (an air pipe failed on the air system resulting in the loss of air). The protection for Unit 4 operated as expected, however stuck contacts on two current monitor relays in the breaker failure circuits for the 230 kV ring bus breakers B2B3 and B3B4 resulted in Units 5 and 6 and TL202 becoming isolated from the system. With the removal of the online Units 3 and 5 (approximately 146 MW) the system frequency dropped to 58.07 Hz resulting in the activation of the underfrequency protection at Hydro and Newfoundland Power. Total system load at the time of the incident was 921 MW. Restoration of service to customers began shortly after the incident as generation output was increased on all available units. There were 42,502 Newfoundland Power customers reported to be restored within two hours and twenty-nine minutes after the event occurred. (Unsupplied Energy: 11,792 MW-Mins) Customers were restored in blocks as generation became available to the system. There were 6,662 Hydro customers restored within forty minutes after the event occurred. (Unsupplied Energy: 288 MW-Mins)

# Appendix D: List of U.S.-Based Peers for Financial KPI Benchmarking

**Generation and Corporate Peer Group:**

Alcoa Power Generating Inc.
Allete, Inc.
Aquila, Inc.
Avista Corporation
Buckeye Power, Inc.
Cleco Power LLC
Electric Energy, Inc.
Entergy Mississippi, Inc.
Hawaiian Electric Company, Inc.
Indiana-Kentucky Electric Corporation
Kentucky Power Company
Ohio Valley Electric Corporation
Portland General Electric Company
Public Service Company of New Hampshire
Puget Sound Energy, Inc.
Savannah Electric and Power Company
Sierra Pacific Power Company
Southern Electric Generating Company
Southern Indiana Gas and Electric Company
The Empire District Electric Company

**Transmission Peer Group:**

AEP Texas North Company
Allete, Inc.
Aquila, Inc.
Avista Corporation
Central Illinois Public Service Company
Delmarva Power & Light Company
Entergy Mississippi, Inc.
Kentucky Utilities Company
MDU Resources Group, Inc.
Mississippi Power Company
New York State Electric & Gas Corporation
Northern Indiana Public Service Company
Northern States Power Company (Wisconsin)
Oklahoma Gas and Electric Company
Public Service Company of Colorado
Public Service Company of Oklahoma
Sierra Pacific Power Company
Southwestern Electric Power Company
Tucson Electric Power Company
Westar Energy, Inc.