Q. Please provide any available studies or assessments of the competitiveness, effectiveness, or economic efficiency of Newfoundland Power operations (field and/or management) in comparison to Newfoundland and Labrador Hydro, other Canadian utilities and US utilities. Such studies or assessments would include any benchmarking undertaken by Newfoundland Power or that includes Newfoundland Power results.

A. **A. Introduction**

The effectiveness and efficiency of Newfoundland Power's operations is routinely considered by the Board through transparent public processes. This is necessary to ensure the Company meets it statutory obligation to deliver reliable service to customers at least cost.[1]

Recent studies or assessments of Newfoundland Power's operations include: (i) an annual benchmarking study; (ii) assessments of the Company's year-over-year performance; and (iii) an independent assessment of Newfoundland Power's engineered operations by The Liberty Consulting Group ("Liberty") in 2014.

B. Annual Benchmarking Study

Since 2005, Newfoundland Power has filed an annual report with the Board entitled *Peer Group Performance Measures for Newfoundland Power*.[2] This report provides a comparison of the Company's performance against a composite of Canadian and U.S. utilities, including Newfoundland and Labrador Hydro ("Hydro").[3]

The most recent report on *Peer Group Performance Measures for Newfoundland Power* was filed with the Board on December 19, 2018 (the "2018 Peer Group Report"). A copy of the 2018 Peer Group Report is provided as Attachment A to this response.[4]

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1 See Section 3(b)(iii) of the *Electrical Power Control Act, 1994.*

2 In Order No. P.U. 19 (2003), the Board ordered Newfoundland Power to file a report suggesting a "peer group" of utilities and performance measures upon which to evaluate the Company's performance. In 2004, Newfoundland Power filed a draft report outlining its initial findings and a supplemental report addressing questions and recommendations from the Board. The first annual report on *Peer Group Performance Measures for Newfoundland Power* was subsequently filed with the Board on February 28, 2005.

3 Newfoundland Power's performance is compared against a composite of Canadian utilities to assess the Company's reliability and safety performance. Specific performance measures are calculated using data from the Canadian Electricity Association ("CEA") and include the: (i) System Average Interruption Frequency Index ("SAIFI"), which measures the frequency of customer outages; (ii) System Average Interruption Duration Index ("SAIDI"), which measures the duration of customer outages; and (iii) All-Injury Frequency Rate, which measures injuries per 200,000 hours worked. As no cost-related CEA composite indicators are available, the Company's performance in that regard is compared to a peer group of U.S. utilities. Cost-related performance measures include, as examples, Total Distribution Operating Expense per Customer, Total Customer Service Expense per Customer, and Total Operating Expense per Energy Sold.

4 The 2018 Peer Group Report provides a comparison of performance measures over a 10-year period, covering 2008 to 2017.

Overall, the 2018 Peer Group Report indicates *"Newfoundland Power's performance generally compares favourably to that indicated by trends in the composite data for Canadian and U.S. utilities."*[5] Newfoundland Power nonetheless maintains that assessing year-over-year trends in the Company's performance provides a more useful indication of the effectiveness and efficiency of its operations in serving customers.

C. Assessments of Year-Over-Year Performance

Newfoundland Power's year-over-year performance is routinely assessed by the Board, including through general rate applications.[6]

The Company's *2019/2020 General Rate Application* (the "Application") was filed with the Board on June 1, 2018.[7] As part of that Application, Newfoundland Power completed various assessments of its performance in serving customers. For example, detailed information on the Company's long-term customer service performance was outlined in responses to Requests for Information PUB-NP-003 and PUB-NP-073. Copies of these responses are provided as Attachments B and C to this response, respectively.

This information shows that, over a 20-year period, Newfoundland Power improved the reliability experienced by customers by 39%.[8] Over the same period, the Company achieved a 23% reduction in operating costs per customer and a 24% reduction in its contribution to customer rates on an inflation-adjusted basis.[9] This performance is consistent with customers' service expectations, with customer satisfaction averaging 87% over the period.[10]

D. 2014 Assessment of Engineered Operations

Newfoundland Power has not completed studies or assessments of its effectiveness or efficiency in comparison to Hydro.

In 2014, following widespread customer outages known as #darkNL, the Board commissioned Liberty to conduct comprehensive, independent assessments of the engineered operations of both Newfoundland Power and Hydro.[11] Copies of these assessments are provided as Attachments D and E to this response, respectively. While

[5] See the 2018 Peer Group Report, page 3.
[6] Newfoundland Power files quarterly and annual reports with the Board to provide information on the Company's performance within a particular timeframe. For more information, see response to Information Request PUB-NP-031.
[7] The Application was filed in accordance with Order No. P.U. 18 (2016).
[8] The improvement in reliability reflects a 39% decrease in both the duration and frequency of customer outages between 1997 and 2017. For more information, see Attachment B, page 3, and Attachment C, page 3.
[9] For more information on operating costs per customer, see Attachment B, page 2. For more information on the Company's contribution to customer rates, see Attachment C, page 4.
[10] For more information on customer satisfaction, see Attachment B, page 4.
[11] The 2014 investigation into *Supply Issues and Power Outages on the Island Interconnected System* is consistent with the Board's authority under Section 37(2) of the *Public Utilities Act.*

Liberty's 2014 assessments do not address the relative performance of the 2 utilities, they provide detailed findings on the effectiveness of both utilities at a particular point in time. This includes assessments of both utilities in comparison to good utility practice.

With respect to Newfoundland Power, Liberty found that:

> "Newfoundland Power's planning and design of its system, its asset management practices, its system operations, its outage management and emergency practices and its customer communications processes *all conform to good utility practices*."[12] [Emphasis added]

Liberty also found that:

> "Newfoundland Power's reliability has improved significantly since 1999 and has recently remained stable overall. Its transmission and distribution systems operate *effectively* in ensuring adequate service reliability. *Effective* maintenance and capital programs, that appropriately recognize the age of its assets, have contributed materially to improved reliability."[13] [Emphasis added]

E. Concluding

Overall, these studies and assessments show: (i) Newfoundland Power's performance is favourable in comparison to other utilities; (ii) its service delivery is responsive to customers' service expectations; and (iii) the Company's engineered operations conform to good utility practice. This overall performance is consistent with effective and efficient utility operations and the delivery of reliable service to customers at least cost.

[12] The Liberty Consulting Group, *Executive Summary of Report on Island Interconnected System to Interconnection with Muskrat Falls addressing Newfoundland Power Inc.*, December 17, 2014, page ES-1.
[13] Ibid., page ES-2.

2018 Peer Group Report

WHENEVER. WHEREVER.
We'll be there.

NEWFOUNDLAND POWER
A FORTIS COMPANY

HAND DELIVERED

December 19, 2018

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

Attention: G. Cheryl Blundon
Director of Corporate Services
and Board Secretary

Ladies and Gentlemen:

Re: Peer Group Performance Measures for Newfoundland Power

On February 28, 2005, Newfoundland Power submitted a report entitled *Peer Group Performance Measures for Newfoundland Power*. The report committed Newfoundland Power to reporting annually on the measures presented therein until otherwise directed by the Board.

Enclosed herewith are the original and 10 copies of a report provided in fulfillment of that commitment.

We trust this is satisfactory. However, if there are any questions or concerns, they should be directed to the undersigned.

Yours very truly,

Gerard M. Hayes
Senior Counsel

c. Shirley Walsh
Newfoundland and Labrador Hydro

Dennis Browne, QC
Browne Fitzgerald Morgan & Avis

Newfoundland Power Inc.
55 Kenmount Road • P.O. Box 8910 • St. John's, NL A1B 3P6
PHONE (709) 737-5609 • FAX (709) 737-2974 • ghayes@newfoundlandpower.com

Peer Group Performance Measures
For Newfoundland Power

December 19, 2018

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1.0 Introduction

In Order No. P.U. 19 (2003), the Board of Commissioners of Public Utilities (the "Board") ordered that Newfoundland Power Inc. ("Newfoundland Power" or "the Company") file with the Board in 2004 a report suggesting a "peer group" of utilities and performance measures upon which to evaluate the Company's performance.

In 2004, the Company submitted a draft report entitled *A Report on Peer Group Performance Measures for Newfoundland Power* which reviewed the Company's initial findings in relation to utility performance measures and benchmarking initiatives. Subsequently, Newfoundland Power submitted a report entitled *A Supplementary Report on Peer Group Performance Measures for Newfoundland Power* addressing questions from the Board and recommending certain additional measures.

On February 28, 2005, the Company submitted a report entitled *Peer Group Performance Measures for Newfoundland Power* (the "February 2005 Report"), which provided comparative statistical data together with an assessment of the appropriateness of the recommended performance measures. The February 2005 Report committed the Company to report annually on the measures presented until otherwise directed by the Board.

This report is provided in fulfillment of the Company's commitment to report annually on the measures presented in the February 2005 Report. The performance information is updated to 2017.

2.0 Performance Measures

This report provides a comparison of Newfoundland Power performance measures against the performance measures of a composite of Canadian and U.S. utilities.

2.1 Canadian Utility Measures

The following measures are presented for comparing the Company's performance against a composite of Canadian utilities:

1. System Average Interruption Frequency Index (SAIFI);
2. System Average Interruption Duration Index (SAIDI); and
3. All-injury Frequency Rate (Injuries per 200,000 hours worked).

As with previous reports, this report uses data compiled by the Canadian Electricity Association ("CEA"). In particular, the report includes data from the CEA's *Annual Service Continuity Report on Distribution System Performance in Electrical Utilities* and *Safety Incident Statistics Reports*.

The number of composite performance measures available from the CEA for publication is limited. As of this date, no cost-related CEA composite indicators have become available for the Company to use in the context of regulatory reporting of peer group performance measures.

Appendix A shows comparisons of the available Canadian utility composite measures and the equivalent Newfoundland Power data.

2.2 U.S. Utility Measures

The following measures are presented for comparing the Company's performance to a peer group of U.S. utilities:

1. Total Distribution Operating Expense per Customer;
2. Total Distribution Operating Expense per MWh;
3. Total Customer Service Expense per Customer;
4. Total Administration and Other Operating Expense per Total Operating Expense (excluding fuel and purchased power);
5. Total Operating Expense per Energy Sold (excluding fuel and purchased power); and
6. Total Operating Expense per Customer (excluding fuel and purchased power).

Appendix B contains comparisons of the composite measures for U.S. utilities and the equivalent Newfoundland Power data. The U.S. composite measures are based on data from 20 utilities. For each measure, the range of individual utility results is provided.

The U.S. measures are based on information filed with the Federal Energy Regulatory Commission ("FERC"). FERC requires major electric utilities under its jurisdiction to annually file prescribed information regarding their operations based on a FERC-defined system of accounts. The FERC filings are public information.

The measures for the U.S. data are presented without any adjustment for exchange rates. With the significant shifting in exchange rates over time, converting U.S. dollar figures to Canadian values would greatly distort cost trends.

Appendix C is a list of the U.S. utilities from which the composite measures in Appendix B were compiled.

3.0 Summary and Conclusion

Ongoing concerns with data availability and quality, coupled with observed differences in the operating profiles of participating utilities, makes it difficult to draw meaningful conclusions regarding the Company's performance relative to other utilities.

Newfoundland Power maintains that year-over-year trending of the Company's own data provides a more useful indication of performance than any comparison with data available in relation to other utilities.

Based on the measures reported herein:

1. Newfoundland Power's reliability performance has fluctuated substantially over the period 2008 to 2017. The fluctuations have been the result of a greater incidence of major system events.

2. Newfoundland Power's cost performance during the period from 2008 to 2017 indicate an overall stable trend. Overall operating costs increased from 2009 onward driven principally by increased pension and benefit costs. Pension and benefit costs were

significantly impacted by the 2011 change in the accounting treatment of Other Post Employment Benefits ("OPEBs") costs.

3. Comparisons are subject to the limitations noted above; however, Newfoundland Power's performance generally compares favourably to that indicated by trends in the composite data for Canadian and U.S. utilities presented in this report.

Appendix A

CEA Composite Comparisons

Appendix A

CEA Composite Comparisons

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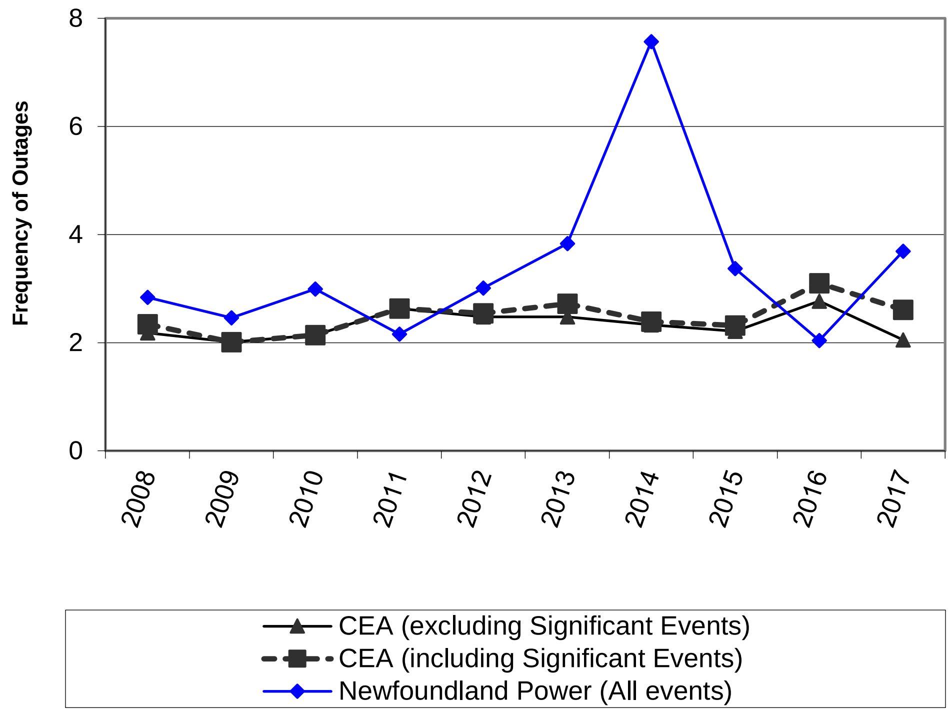
Measure **Page**

System Average Interruption Frequency Index (SAIFI)



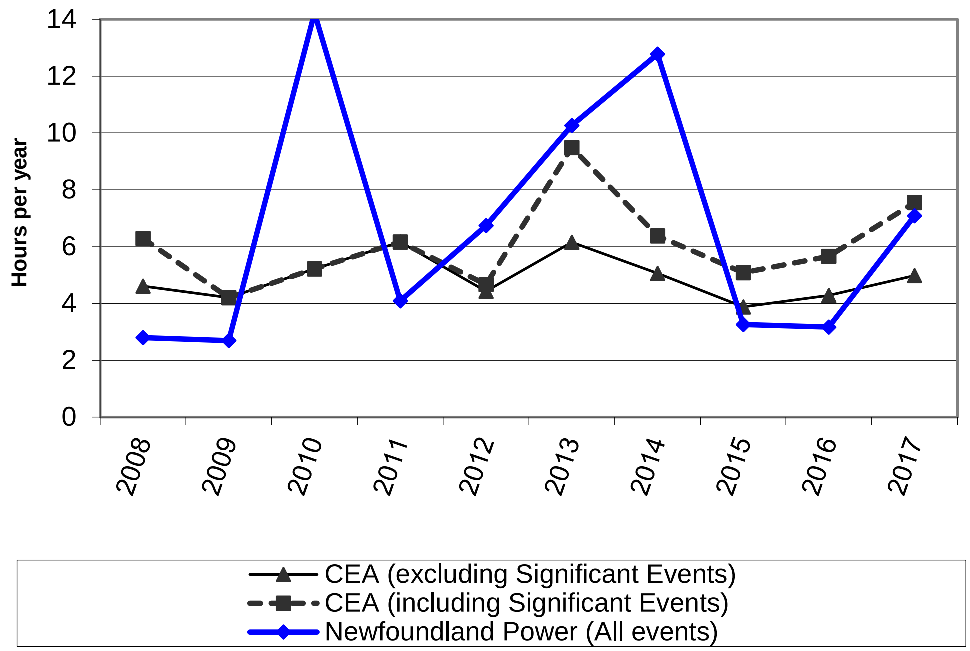
Year	CEA (Excluding Significant Events)	CEA (Including Significant Events)	Newfoundland Power
2008	2.18	2.34	2.84
2009	2.01	2.01	2.46
2010	2.14	2.14	2.99
2011	2.63	2.63	2.16
2012	2.48	2.54	3.01
2013	2.48	2.72	3.83
2014	2.33	2.39	7.57
2015	2.21	2.32	3.37
2016	2.77	3.10	2.04
2017	2.05	2.61	3.69

SAIFI is a standard industry index representing the average number of interruptions per customer served per year.

The CEA trend line reflects the composite performance of participating Canadian utilities (42 participants in 2017). The trend line shows that the frequency of service interruptions to customers has been relatively stable over the period 2008 to 2017.

For Newfoundland Power, the data trend indicates a stable trend in the frequency of customer outages from 2008 to 2011. The increase in 2010 was due to a significant weather event in March and Hurricane Igor in September. Subsequent to 2011, the data reflects the impact of Tropical Storm Leslie in September 2012, and the loss of supply events of January 2013 and January 2014. The increase in 2017 was a result of severe weather events in March and December.

System Average Interruption Duration Index (SAIDI)



Year	CEA (excluding Significant Events)	CEA (including Significant Events)	Newfoundland Power
2008	4.61	6.29	2.80
2009	4.20	4.20	2.69
2010	5.22	5.22	14.22
2011	6.16	6.16	4.09
2012	4.43	4.66	6.74
2013	6.15	9.49	10.26
2014	5.06	6.38	12.77
2015	3.88	5.08	3.26
2016	4.28	5.66	3.17
2017	4.98	7.55	7.09

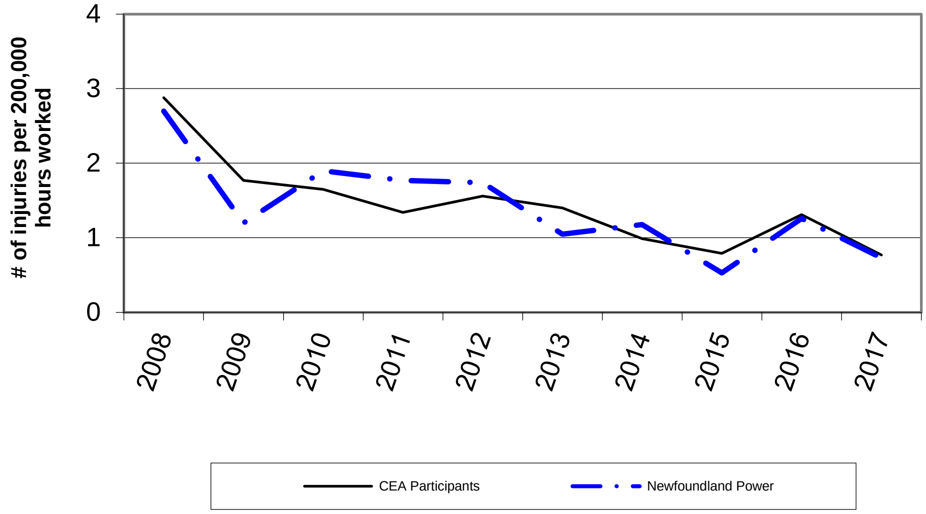
SAIDI is a standard industry index representing the average interruption duration per customer served per year.

The CEA trend line reflects the composite performance of participating Canadian utilities (42 participants in 2017). The trend lines show significant variability year over year. The fluctuations are principally due to the inclusion of outages caused by significant weather events. When significant events are excluded, there is a relatively stable trend line for the CEA composite.

The anomalous results evident in the "CEA including Significant Events" trend line reflect storms in Ontario in 2008, 2011 and 2013.

For Newfoundland Power, the data trend reflects a greater incidence of major events. The increases in 2010, 2012 and 2017 were a result of significant weather events. Those events include severe winter storms in March 2010, Hurricane Igor in September 2010, Tropical Storm Leslie in September 2012 and the severe winter storms in March and December of 2017. The increases in 2013 and 2014 were due to loss of supply.

All-injury Frequency Rate
(Injuries per 200,000 hours worked)



Year	CEA Composite	Newfoundland Power
2008	2.88	2.70
2009	1.77	1.20
2010	1.65	1.90
2011	1.34	1.77
2012	1.56	1.74
2013	1.40	1.05
2014	0.99	1.18
2015	0.79	0.53
2016	1.31	1.26
2017	0.77	0.73

This measure represents the rate of disabling injuries and medical aid injuries per 200,000 exposure hours (hours worked).

The CEA data is a composite of 10 participating Canadian utilities. Both the CEA and Newfoundland Power trend lines show a comparable level of improvement.

Appendix B

American (U.S.) Peer Group Composite Comparisons

Appendix B

American (U.S.) Peer Group Composite Comparisons

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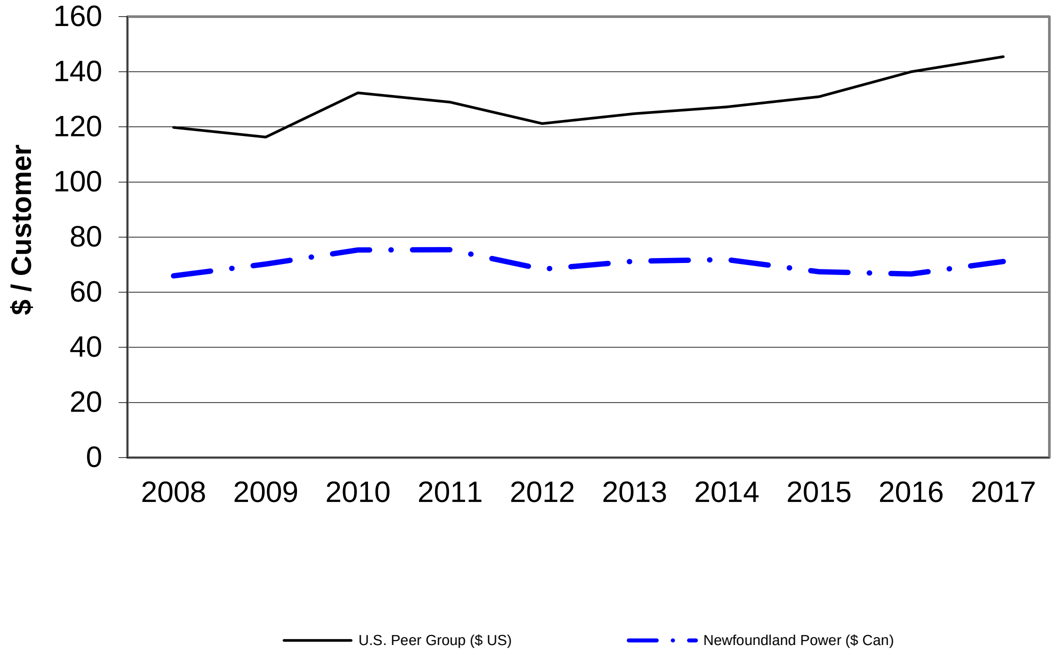
Measure **Page**

Total Distribution Operating Expense per Customer (2017$)



Year	U.S. Peer Group Composite	Newfoundland Power
2008	119.8	65.9
2009	116.3	70.2
2010	132.4	75.3
2011	128.9	75.4
2012	121.1	68.4
2013	124.8	71.2
2014	127.2	71.8
2015	130.9	67.5
2016	140.0	66.6
2017	145.5	71.2

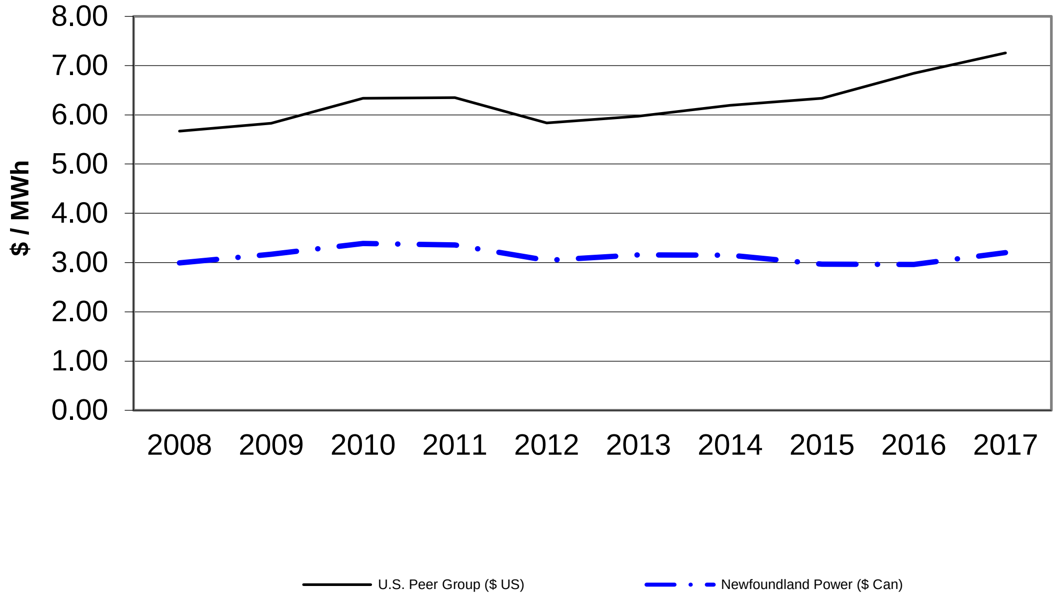
This measure represents the total cost of operating and maintenance for the distribution function, as defined under the FERC code of accounts, expressed on a per customer account basis and adjusted for inflation. It measures the total direct cost of operating labour and materials, excluding allocated corporate shared services, involved in the operation and maintenance of the distribution portion of the electrical system, expressed on a per customer basis.[1]

The graph shows a stable trend for Newfoundland Power over the period from 2008 to 2017.

While the numbers fluctuated, the U.S. utility data shows the distribution operating cost per customer to be increasing steadily. The U.S. utilities' individual 2017 measures range from approximately $70 to approximately $258 per customer.

[1] The distribution system is the portion of the electrical system that links the transmission system to customer facilities.

Total Distribution Operating Expense per MWh
(2017$)



Year	**U.S. Peer Group Composite**	**Newfoundland Power**
2008	5.67	2.99
2009	5.83	3.17
2010	6.34	3.39
2011	6.35	3.36
2012	5.83	3.04
2013	5.97	3.16
2014	6.19	3.15
2015	6.34	2.97
2016	6.84	2.96
2017	7.26	3.20

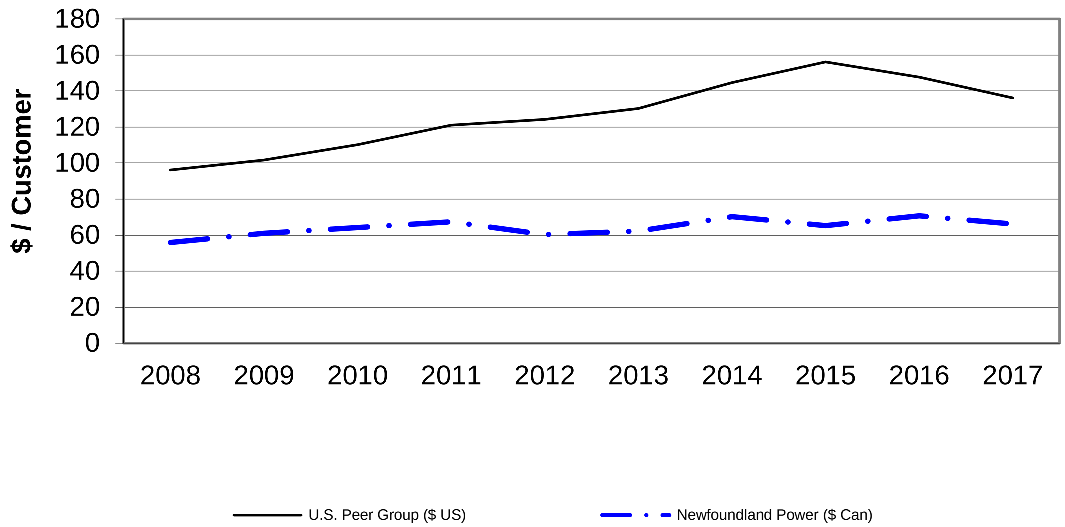
This measure represents the total cost of operating and maintenance for the distribution function, as defined under the FERC code of accounts, expressed on a per MWh of retail sales basis and adjusted for inflation. It measures the total direct cost of operating labour and materials, excluding allocated corporate shared services, involved in the operation and maintenance of the distribution portion of the electrical system, expressed on a per MWh basis.

The MWh of retail sales includes the total MWh sales of electricity as per retail rate schedules. It does not include sales for resale such as those to other distribution companies and retailers, nor energy interchanged through the power system (usually through transmission facilities).

The U.S. peer group trend has steadily increased over the reporting period; the increase is largely due to reduced sales. The U.S. utilities' individual 2017 measures range from approximately $2 to approximately $20 per MWh.

The graph shows a stable trend for Newfoundland Power from 2008 to 2017.

Total Customer Service Expense per Customer
(2017$)



Year	U.S. Peer Group Composite	Newfoundland Power
2008	96.1	55.9
2009	101.7	61.0
2010	110.2	64.1
2011	121.1	67.4
2012	124.2	60.3
2013	130.3	62.2
2014	144.7	70.2
2015	156.1	65.3
2016	147.6	70.7
2017	136.2	66.1

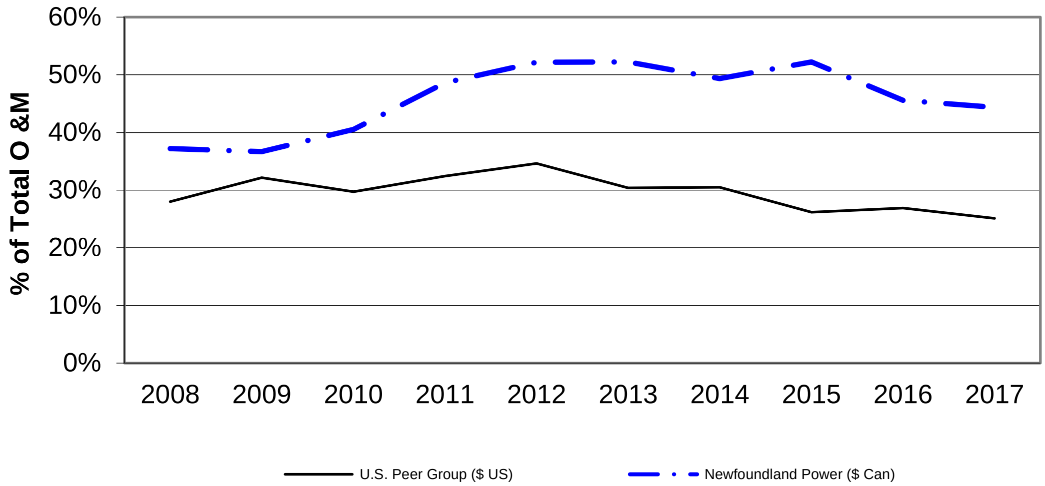
This measure represents the total cost of operating and maintenance for the customer accounting and customer service functions, as defined under the FERC code of accounts, expressed on a per customer account basis and adjusted for inflation. It measures the total direct cost of operating labour and materials, excluding allocated corporate shared services, associated with the management of customer relations and billing functions, expressed on a per customer account basis.

Newfoundland Power's data indicates a relatively stable trend over the 10 year period from

2008 - 2017.

The U.S. peer group composite increased between 2008 and 2015 and shows a decline since then. The U.S. utilities' individual 2017 measures range from approximately $30 to approximately $301 per customer.

Total Administration and Other Operating Expense per Total Operating Expense
(excluding fuel and purchased power)



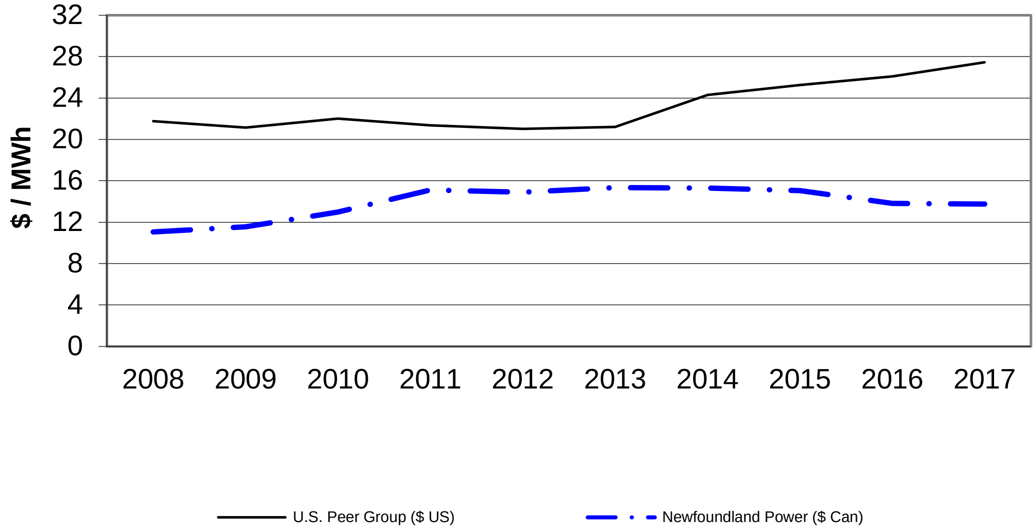
Year	U.S. Peer Group Composite	Newfoundland Power
2008	28.0%	37.2%
2009	32.2%	36.7%
2010	29.7%	40.5%
2011	32.5%	48.6%
2012	34.6%	52.1%
2013	30.4%	52.2%
2014	30.5%	49.3%
2015	26.2%	52.2%
2016	26.9%	45.6%
2017	25.6%	44.3%

This measure is a ratio of the total administration and general expense to the overall corporate electrical operating and maintenance expense (excluding fuel and purchased power) as defined by the FERC code of accounts.

The trend line for the U.S. utilities shows a general decline since 2012. The U.S. utilities' individual 2017 measures varied from approximately 5% to 49%.

The Newfoundland Power data for 2008 through 2017 reflects material changes in pension and benefit costs, including an increase in costs due to the 2011 change in the accounting treatment of OPEBs costs.

Total Operating Expense
per Energy Sold
(excluding fuel and purchased power, 2017$)



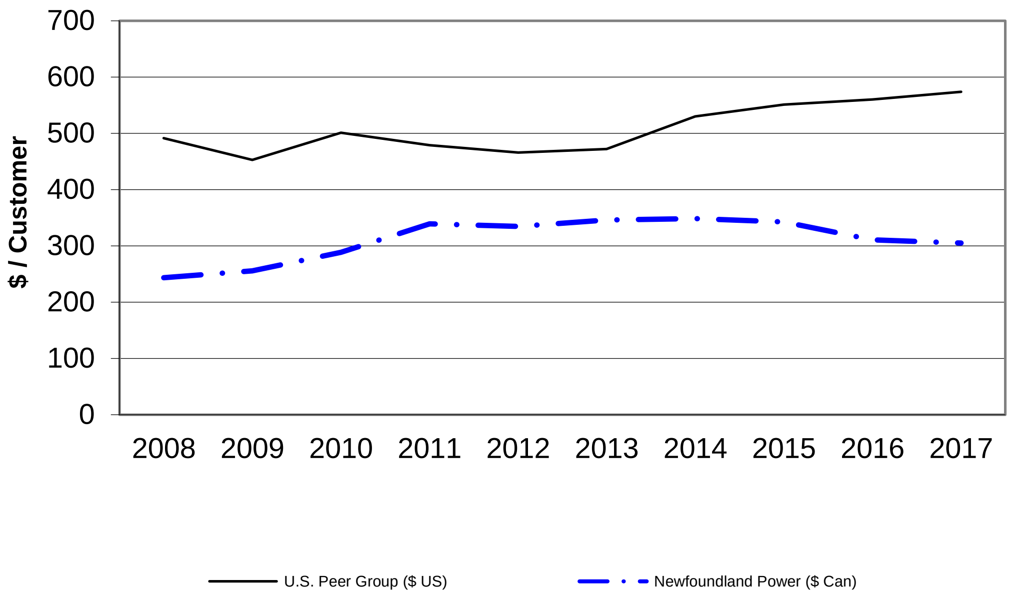
Year	U.S. Peer Group Composite	Newfoundland Power
2008	21.8	11.1
2009	21.1	11.6
2010	22.0	13.0
2011	21.4	15.1
2012	21.0	14.9
2013	21.2	15.3
2014	24.3	15.3
2015	25.3	15.1
2016	26.1	13.8
2017	26.9	13.7

This measure represents the electrical operating and maintenance expense (excluding fuel and purchased power), as defined by the FERC code of accounts, expressed on a per MWh of total energy sold basis and adjusted for inflation. Total energy sold includes sales according to retail rate schedules, and sales for resale, such as sales to other distribution companies, sales to retailers, and energy interchanged through the power system (usually through transmission facilities).

The trend line for the U.S. utilities is upward over the period 2008 to 2017. The U.S. utilities' individual 2016 measures varied from approximately $5 to $122 per MWh.

The graph shows a relatively stable trend for Newfoundland Power since 2011. For 2011 through 2017, the measure reflects the effect of material changes in pension and benefit costs, including an increase in costs due to the 2011 change in the accounting treatment of OPEBs costs.

Total Operating Expense per Customer
(excluding fuel and purchased power, 2017$)



Year	U.S. Peer Group Composite	Newfoundland Power
2008	491.76	243.64
2009	452.94	256.06
2010	501.40	288.64
2011	479.24	339.14
2012	465.79	334.69
2013	472.11	345.97
2014	530.14	348.66
2015	551.45	342.63
2016	560.57	311.17
2017	563.18	305.49

This measure represents the electrical operating and maintenance expense (excluding fuel and purchased power), as defined by the FERC code of accounts, expressed on a customer account basis and adjusted for inflation.

The trend line for the U.S. utilities is upward over the reporting period. The U.S. utilities' individual measures in 2017 varied from approximately $219 to approximately $4,057.

The graph shows a stable trend for Newfoundland Power since 2011. For this period, the measure reflects material changes in pension and benefit costs, including an increase in costs due to the 2011 change in the accounting treatment of OPEBs costs.

Appendix C

Companies Included in U.S. Utility Peer Group

Companies Included in U.S. Utility Peer Group
(2017 Information)

Company	Number of Customers	Sales (MWh)	% Production of Total O & M	% Transmission of Total O & M
Ameren Illinois Company	1,221,130	35,241,466	8.5%	9.9%
Atlantic City Electric Company	551,332	8,584,533	7.1%	6.9%
Central Hudson Gas & Electric	257,812	2,560,833	2.1%	5.3%
Delmarva Power & Light Company	520,657	11,876,306	4.7%	8.9%
Duke Energy Kentucky, Inc.	141,274	3,957,490	68.7%	8.5%
Duquesne Light Company	594,106	12,672,936	0.8%	5.4%
Emera Maine	162,912	1,936,940	0.1%	10.9%
Green Mountain Power Corporation	263,528	4,146,862	13.1%	45.8%
Jersey Central Power & Light Company	1,122,087	20,319,843	0.0%	7.3%
Kingsport Power Company	47,840	1,971,080	0.0%	7.6%
Madison Gas and Electric Company	152,601	3,240,863	42.8%	22.2%
Metropolitan Edison Company	566,695	13,776,593	1.4%	8.5%
New York State Electric & Gas Corporation	893,783	15,363,789	6.7%	7.6%
Orange and Rockland Utilities, Inc.	231,066	3,872,536	0.2%	8.5%
Rockland Electric Company	73,345	1,538,962	0.0%	3.8%
The Narragansett Electric Company	422,165	3,868,162	0.0%	19.3%
Unitil Energy Systems, Inc.	78,722	1,193,912	0.5%	53.9%
West Penn Power Company	724,589	19,585,829	0.0%	27.4%
Western Massachusetts Electric Company	210,928	3,441,445	0.2%	15.2%
Wheeling Power Company	41,427	3,916,764	67.9%	19.3%

Response to Request for Information PUB-NP-003
Newfoundland Power's *2019/2020 General Rate Application*

Q. Page 1-4, line 10: Please explain the basis for the statement that Newfoundland Power demonstrates "sound cost management".

A. **A. General**

Section 3(b)(iii) of the *Electrical Power Control Act, 1994,* requires Newfoundland Power to manage its operations in a manner that results in power being delivered to customers at the lowest possible cost consistent with reliable service.

Demonstrating sound cost management requires the Company to control its costs without compromising the level of service experienced by customers. To accomplish this, Newfoundland Power has taken a long-term view to balancing sustainable cost management, system reliability and service responsiveness.

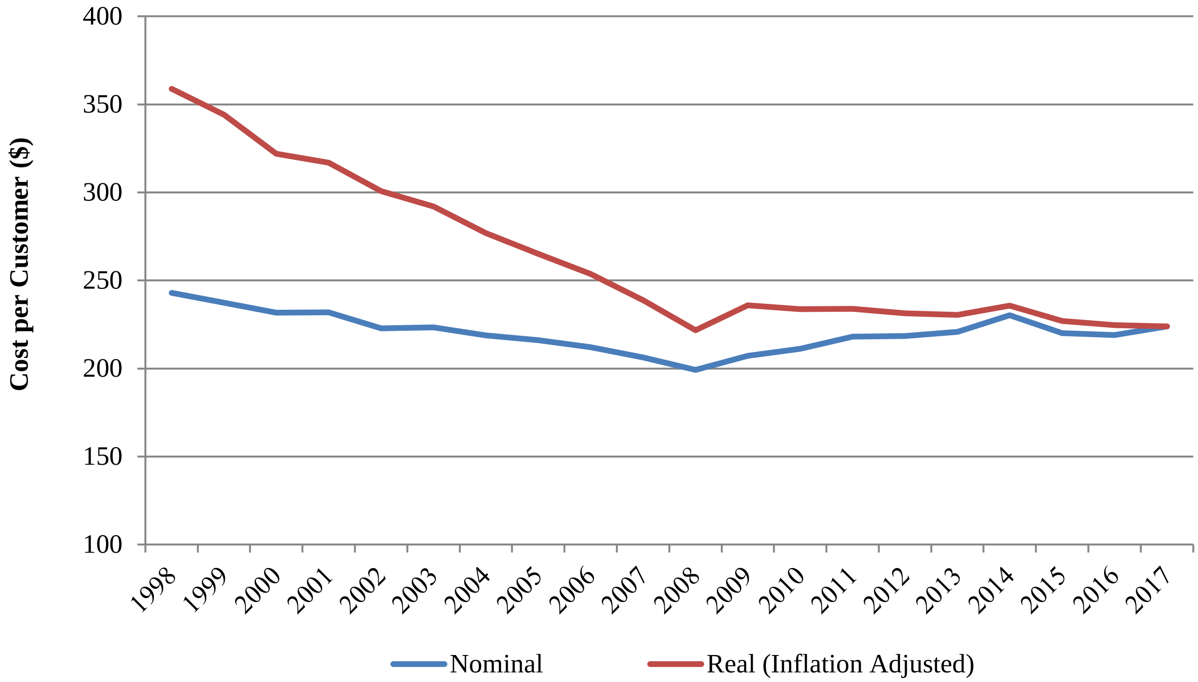
B. Operating Cost per Customer

Newfoundland Power has achieved improvements in operating efficiency and has sustained these improvements over the longer term. One measure of operating efficiency is the Company's operating cost per customer.

Figure 1 shows the Company's gross operating cost per customer on a nominal and real (i.e. inflation-adjusted) basis for the period 1998 to 2017.[1]

[1] On a nominal basis, gross operating costs per customer were lower in 2008, primarily as a result of a one-time change in an accounting methodology. Further, inflation of approximately 4% in 2008 was above average for the period of approximately 2%.

Figure 1:
Operating Cost per Customer
(1998 to 2017)



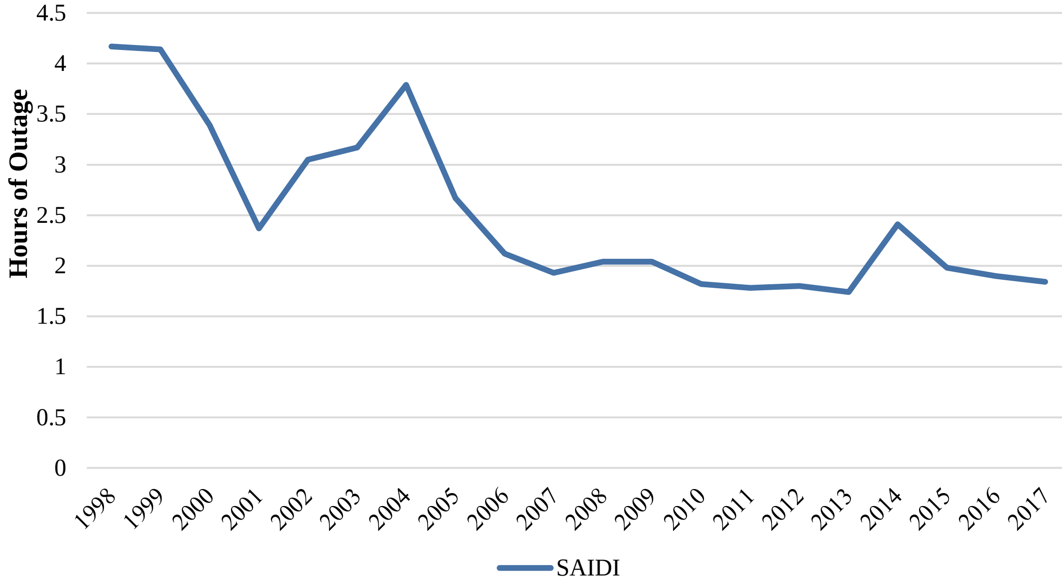
Over the 10-year period of 1998 to 2007, Newfoundland Power's average gross operating cost was approximately $297/customer. Over the most recent 10-year period, the Company's average gross operating cost was approximately $230/customer. This represents a 23% reduction in costs on a per-customer basis.

C. Electrical System Reliability

Newfoundland Power has achieved operating efficiencies while improving the reliability experienced by customers.

Figure 2 shows the average duration of customer outages experienced on Newfoundland Power's electrical system for the period 1998 to 2017.

Figure 2:
Unplanned Outages Duration (SAIDI)
Normal Operating Conditions
1998 to 2017



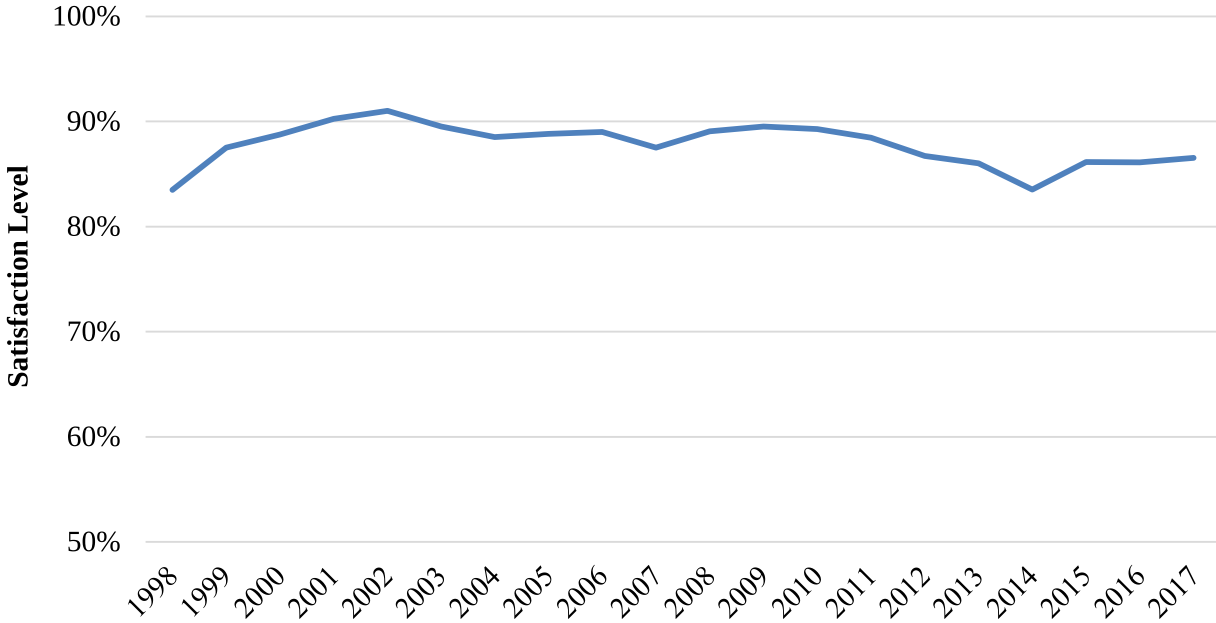
From 1998 to 2007, customers experienced an average outage duration of 3.1 hours. Over the most recent 10-year period, customers experienced an average outage duration of 1.9 hours. This represents a 39% improvement in the reliability experienced by customers.

D. Customer Satisfaction

In addition to sustained improvements in operating efficiency and system reliability, customer satisfaction with Newfoundland Power's service delivery has remained reasonably consistent.

Figure 3 shows customers' annual average satisfaction with Newfoundland Power's service delivery for the period 1998 to 2017.

Figure 3:
Average Annual Customer Satisfaction
1998 to 2017



Over the 10-year period from 1998 to 2007, customers were 88% satisfied with Newfoundland Power's service delivery. Over the most recent 10-year period, customers have indicated an average satisfaction level of 87%. This indicates reasonable levels of customer satisfaction have been maintained over the long term.

E. Overall Performance

Overall, Newfoundland Power's improvements in operating efficiency and system reliability, in addition to sustained customer satisfaction, indicate the Company has demonstrated sound cost management over the long term.

More details on the specific initiatives the Company has implemented to manage its costs are provided in response to Request for Information PUB-NP-002.

Response to Request for Information PUB-NP-073
Newfoundland Power's *2019/2020 General Rate Application*

Q. Given the increase in business risks since the last general rate application referred to in the Application of the decline in the provincial economy and the rate increases required for the Muskrat Falls Project and the response to CA-NP-025 on actions to alleviate electricity price increases, is Newfoundland Power of the opinion that it should consider additional cost savings initiatives to those listed in the response to PUB-NP-002 to reduce, to the extent possible, imminent rate increases for customers? If not, why not? If yes, explain the approach that could be followed, including whether the implementation of a productivity or cost reduction allowance would be effective?

A. **A. Response**

The provincial power policy outlined in the *Electrical Power Control Act, 1994* effectively requires Newfoundland Power to manage its operations in a manner that results in power being delivered to customers at *the lowest possible cost consistent with reliable service.*[1] The Company is of the opinion that its existing approach to cost management is consistent with this statutory requirement and continues to be appropriate.

Limiting Newfoundland Power's cost recovery in the manner suggested in this question would, in the Company's opinion, be inconsistent with: (i) customers' service expectations; (ii) independent assessment of Newfoundland Power's engineered operations; and (iii) the Company's history of least-cost, reliable service delivery. In Newfoundland Power's view, such a limitation on cost recovery would also be contrary to public policy, which permits recovery of costs that are consistent with the least-cost delivery of reliable service to customers.

B. Evaluating Newfoundland Power's Performance

Customers' Expectations

Generally, the majority of customer outages on an electrical system occur at the distribution level.[2] Maintenance of the distribution system, therefore, typically has the most direct impact on the reliability experienced by customers.

The importance of service reliability to Newfoundland Power's customers was demonstrated in January 2014 during #darkNL. #darkNL was a 7-day period during which 75% of the Company's customers experienced rotating power outages. The event occurred during cold temperatures, posed serious risks to public health and safety, and

[1] See Section 3(b)(iii) of the *Electrical Power Control Act, 1994*.
[2] For Region 2 utilities, the Canadian Electricity Association notes that 85% of outage hours in the last 5 years are attributable to distribution-level outages. See *2017 Service Continuity Data on Distribution System Performance in Electrical Utilities*.

was not viewed as acceptable by customers.[3]

The Board's consultant in its investigation of #darkNL, The Liberty Consulting Group ("Liberty"), found that #darkNL was caused by the insufficiency of generating resources and issues with the operation of key transmission assets.[4] Inadequate maintenance practices contributed to these failures.

Since 2014, service reliability has remained one of the most important issues to customers. Quarterly customer satisfaction surveys indicate customers are currently satisfied with the reliability of Newfoundland Power's service delivery.[5]

Independent Assessment of Engineered Operations

Public policy requires Newfoundland Power to deliver service that is safe and adequate and just and reasonable.[6] Following #darkNL, the Board had Liberty conduct a comprehensive review of the engineered operations of both Newfoundland Power and Newfoundland and Labrador Hydro ("Hydro").[7]

With respect to Newfoundland Power, Liberty found that:

> "Newfoundland Power's planning and design of its system, its asset management practices, its system operations, its outage management and emergency practices and its customer communications processes all conform to good utility practices."[8]

Liberty also found that:

> "Newfoundland Power's reliability has improved significantly since 1999 and has recently remained stable overall. Its transmission and distribution systems operate effectively in *ensuring adequate service reliability*. Effective maintenance and capital programs, that appropriately recognize the age of its assets, have contributed materially to improved reliability."[9] [Emphasis added]

Liberty's comprehensive review clearly indicated that Newfoundland Power's current

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3 Of the 80 customer satisfaction surveys issued between 1998 and 2017, the lowest score recorded at any point was in the first quarter of 2014 following #darkNL. Newfoundland Power's customer satisfaction score was 82% during that quarter. This compares to an average of 88% over the 20-year period from 1998 to 2017.

4 The Liberty Consulting Group, *Executive Summary of Report on Island Interconnected System to Interconnection with Muskrat Falls addressing Newfoundland Power Inc.*, December 17, 2014, page ES-1.

5 Newfoundland Power's average customer satisfaction was 87% in 2017.

6 See Section 37(1) of the *Public Utilities Act.*

7 Section 37(2) of the *Public Utilities Act* provides that the Board may appoint a person to investigate whether a utility's service is reasonably safe and adequate and just and reasonable.

8 The Liberty Consulting Group, *Executive Summary of Report on Island Interconnected System to Interconnection with Muskrat Falls addressing Newfoundland Power Inc.*, December 17, 2014, page ES-1.

9 Ibid., page ES-2.

strategy for reliability management is consistent with sound public utility practice.[10]

Newfoundland Power's History of Least-Cost, Reliable Service Delivery

Electrical system reliability is primarily a function of construction standards, inspection and maintenance practices, and the systematic deployment of resources.[11] Newfoundland Power has considered existing levels of electrical system reliability to be adequate for about a decade.[12]

Table 1 compares Newfoundland Power's reliability performance in 1997 and 2017 under normal operating conditions.[13]

Table 1:
Newfoundland Power's Reliability Performance
(Normal Operating Conditions)

	1997	**2017**	**% Change**
SAIFI	2.72	1.66	-39%
SAIDI	3.73	2.28	-39%

Table 1 shows customers have experienced a 39% improvement in service reliability over the last 2 decades. This improvement is reflected in both the frequency and duration of customer outages.

[10] Section 4 of the *Electrical Power Control Act, 1994* effectively requires the Board to apply tests that are consistent with generally accepted sound public utility practice in implementing the power policy contained in the *Electrical Power Control Act, 1994* and the *Public Utilities Act.*

[11] More information on Newfoundland Power's approach to reliability management is provided in response to Request for Information PUB-NP-019. Newfoundland Power's approach to least-cost, reliable service delivery is typically reviewed by the Board in general rate applications.

[12] In Newfoundland Power's *2010 General Rate Application,* filed on May 28, 2009, the Company stated it considered then current levels of service reliability to be satisfactory (see Volume 1 (1st Revision), Section 2: Customer Operations, Page 2-8, Line 6). Similarly, the Company has characterized its electrical system performance as reliable in both its *2013/2014 General Rate Application* (see Volume 1, Section 1: Introduction, Page 1-3, Line 10) and its *2016/2017 General Rate Application* (see Volume 1 (1st Revision), Section 1: Introduction, Page 1-3, Line 11).

[13] Reliability data provided in Table 1 excludes loss of supply and significant events.

Table 2 compares Newfoundland Power's *total* contribution to average customer rates in cents per kWh in 1997 and 2017.[14]

Table 2:
Newfoundland Power
Contribution to Customer Rates

Unit Cost (¢/kWh)		% Change	
1997	**2017**	**Nominal**	**Real**
3.56	3.99	12%	-24%

Table 2 shows that Newfoundland Power's contribution to average customer rates (¢/kWh) has increased by a total 12% over the last 2 decades. Inflation over this period was approximately 47%.[15] On an inflation-adjusted, or real, basis, Newfoundland Power's contribution to average customer rates decreased by 24%.

The Company's management of its engineered operations has resulted in an improvement in reliability of almost 40% at a reduced cost to customers of approximately 24% over the past 2 decades. This is consistent with Newfoundland Power's fulfillment of its obligation to deliver reliable service to customers at least cost.

C. Public Policy Perspective

Newfoundland Power's costs of serving customers have been incurred in a manner consistent with the provincial power policy reflected in the *Electrical Power Control Act, 1994* and the *Public Utilities Act.* The Company's capital expenditures are reviewed annually in public applications to the Board. Newfoundland Power's annual operating costs are typically interrogated by the Board on a triennial basis through general rate applications, including the Company's current Application. Through these processes, the Board determines what Newfoundland Power costs are consistent with the delivery of least-cost, reliable service to customers and should be recovered through customer rates.

Nalcor Energy's Muskrat Falls Project is the single most costly electrical system investment in the history of Newfoundland and Labrador. Unlike Newfoundland Power's costs, the significant costs related to Nalcor Energy's Muskrat Falls Project have not been subject to the *Public Utilities Act* or the *Electrical Power Control Act, 1994.*[16] As a

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[14] Newfoundland Power's contribution to average customer rates, as shown in Table 2, reflects the Company's total cost to serve customers, including all operating costs, depreciation, taxes, and return. It excludes purchased power costs and costs recovered through the Rate Stabilization Account. Total Newfoundland Power costs are divided by sales to determine the cost expressed as cents per kilowatt-hour.

[15] Newfoundland Power calculates inflation using the GDP Deflator for Canada. This is consistent with Order No. P. U. 36 (1998-99).

[16] See the *Muskrat Falls Project Exemption Order under the Electrical Power Control Act, 1994 and the Public Utilities Act* (O.C. 2013-342), dated November 29, 2013.

result, these costs have never been adjudged to be reasonable or consistent with the least-cost delivery of reliable service to customers.[17]

In Newfoundland Power's view, it would be contrary to existing public policy to limit the Company's ability to recover its reasonable costs of delivering reliable service to customers. This includes limiting Newfoundland Power's cost recovery to permit recovery of costs related to Nalcor Energy's Muskrat Falls Project, which have never been determined to be reasonable or consistent with the least-cost delivery of reliable service.

[17] On November 20, 2017, the Government of Newfoundland and Labrador announced a public inquiry into the Muskrat Falls Project (the "Muskrat Falls Inquiry"). The Muskrat Falls Inquiry will examine the sanction, construction and oversight of the Muskrat Falls Project and the future operation of the provincial electrical system. Public hearings associated with the Muskrat Falls Inquiry are scheduled to begin in September 2018 and continue into the third quarter of 2019.

The Liberty Consulting Group
2014 Report Addressing Newfoundland Power Inc.

Supply Issues and
Power Outages Review
Island Interconnected System

Executive Summary
of
Report on
Island Interconnected System to Interconnection with Muskrat Falls
addressing
Newfoundland Power Inc.

Presented to:

The Board of Commissioners of Public Utilities
Newfoundland and Labrador

Presented by:

The Liberty Consulting Group

December 17, 2014

279 North Zinns Mill Road, Suite H
Lebanon, PA 17042-9576

Executive Summary

Background to Liberty's Examination

- The Board of Commissioners of Public Utilities ("Board") retained The Liberty Consulting Group ("Liberty") to examine the causes of widespread electricity outages experienced by customers on the Island Interconnected System ("IIS) of Newfoundland and Labrador from January 2 through 8, 2014. This report follows an April 2014 Interim Report from Liberty.
- This report: (a) confirms the outage causes described in the Interim Report, (b) examines the actions Newfoundland Power has taken to address the directions from the Board's May 2014 Interim Report, the recommendations in our Interim Report, and additional initiatives identified by Newfoundland Power and (c) reviewed the adequacy and reliability of Newfoundland Power's system, including its efforts to sustain reliability at appropriate levels. We remain engaged in a review (expected to be completed in the spring of 2015) of the reliability impacts that will follow the interconnection of Muskrat Falls generation through the Labrador-Island Link.
- Liberty has been serving utility regulators for more than 25 years, working on hundreds of projects across the full range of areas involved in ensuring safe, reliable, and cost effective utility service. Liberty's work extends to 55 North American jurisdictions, ranging from some of the continent's most expansive holding companies to small providers that serve largely rural areas. Liberty has examined reliability and outage response in extreme weather, hurricane, flood, and wind conditions.

Overall Conclusions

- Liberty continues to conclude, in full accord with our Interim Report, that the outages of January 2014 stemmed from two differing sets of causes: (a) the insufficiency of Newfoundland & Labrador Hydro ("Hydro") generating resources to meet customer demands, and (b) issues with the operation of key equipment on Hydro's transmission system.
- Newfoundland Power's planning and design of its system, its asset management practices, its system operations, its outage management and emergency practices and its customer communications processes all conform to good utility practices. Liberty has identified additional opportunities to enhance performance in certain areas as described in this report.
- Newfoundland Power's reliability performance has been better than Canadian comparators on standard reliability metrics for the last five years.
- Past conservation efforts have focused on energy savings. Current capacity circumstances, however, dictate a robust consideration of short-term demand-management options. Work in that direction, planned for imminent commencement needs to consider a sufficiently broad range of Muskrat Falls in-service dates, in order to properly assess the pay-back periods of short-term options. Completion of that work needs to be accelerated as much as possible. As our companion report addressing Hydro observes, this work needs to be a fully joint effort between Hydro and Newfoundland Power.

Reliability

- Newfoundland Power's reliability has improved significantly since 1999 and has recently remained stable overall. Its transmission and distribution systems operate effectively in ensuring adequate service reliability. Effective maintenance and capital programs, that appropriately recognize the age of its assets, have contributed materially to improved reliability.
- Liberty does recommend a more formal method for prioritizing capital projects and additional ways to reduce the number of equipment caused failures on the distribution system. Liberty also recommends that Newfoundland Power increase the emphasis on the Rebuild Distribution Lines segment of its annual capital budgeting and evaluate reinstituting a regular annual program for addressing worst-performing feeders.
- The expanded role of the Inter-Utility System Planning and Reliability Committee commenced in 2014 should continue as it will improve planning and coordination between Newfoundland Power and Hydro.

Planning and Design

- The planning and design of Newfoundland Power's system has been effective. It incorporates appropriate levels of redundancy and employs appropriate design standards, criteria, and practices. The Company, however, can extend the use of SCADA and automatic reclosers to minimize interruption frequencies and durations. Completion of in-process developments in the Geographic Information System will increase its effectiveness.
- Newfoundland Power's protective relays schemes conform to industry practice, but require documented guidance. The Company is addressing what has been a temporary delay in testing of electromechanical relays. Liberty recommends that Newfoundland Power address the lack of a program requiring periodic exercising of circuit breakers and that it begin to track centrally actions to address the causes of frequent protective device operations.

Asset Management

- The program, organization, and staffing of Newfoundland Power's asset management functions are sound. The Company uses an effective combination of periodic inspection and maintenance programs and capital rebuild and modernization projects. Vegetation management practices also conform to good utility practices.
- Newfoundland Power's transmission line and pole inspection and corrective maintenance practices conform to good utility practices. Liberty does recommend that Newfoundland Power examine the benefits of chemical treatment of poles and periodic testing of aged poles for internal decay.

System Operations

- System operations structure, staffing, systems, tools, and practices are effective. Liberty does recommend examining the addition of a dedicated training console. The planned replacement of the SCADA system and its Outage Management System should further improve the effectiveness of system operations.
- Newfoundland Power does not employ its own Energy Management System, but links to Hydro's. This arrangement is currently satisfactory.
- The operation and maintenance of Newfoundland Power's generation has been appropriate and the units have maintained a reasonable level of generating availability. The Company has

analyzed and is addressing issues, such as water and fuel supply, that may enhance the capacity it can make available to the Island Interconnected System during periods of generation shortage.

Outage Management

- Newfoundland Power's approach, organization, staffing and practices associated with outage management are effective. Numbers and locations of field personnel are consistent with outage-related needs and the Company appropriately responds to trouble calls. The Outage Management System has served adequately, but the Company is appropriately moving to a commercially provided replacement.
- Customers have appropriate options for reporting outages and restoration information. Newfoundland Power conducts an effective process for estimating restoration times following outages. Those processes should improve with the replacement of the existing SCADA system.

Emergency Management

- Newfoundland Power's emergency response practices, resources, training, and drilling are effective and consistent with good utility practices. The Company has made effective pre-assignment of management and operational duties for its emergency management organization. Its Emergency Command Center has appropriate capability and functionality.
- Storm tracking practices and capabilities support preparation for major weather events. A range of in-house and contractor resources are available for timely restoration for even severe weather events. The System Restoration Manual is consistent with good utility practice, but a clear description of actions for insufficient generation should be added.

Customer Communications

- Newfoundland Power has made significant progress on the outage improvement recommendations made in Liberty's Interim Report, however, important monitoring work remains. The Company should monitor the "customer experience" of the new multi-channel communications services, and adjust the service offering as necessary to ensure a good customer experience.

Supply Issues and Power Outages Review Island Interconnected System

Report on Island Interconnected System to Interconnection with Muskrat Falls
addressing
Newfoundland Power

Presented to:

The Board of Commissioners of Public Utilities
Newfoundland and Labrador

Presented by:

The Liberty Consulting Group

December 17, 2014

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I. Introduction

A. Events Leading to The Board's Investigation

The interconnected electrical system serving the vast majority of customers on the island of Newfoundland (the Island Interconnected System, or "IIS") has experienced significant outages in each of the past two winter seasons.

In January, 2013 a series of events on the system of Newfoundland and Labrador Hydro ("Hydro") produced Island-wide, extensive customer outages, primarily on the Avalon Peninsula. The next year, in January 2014 conditions on Hydro's system caused two series of outages across the period from January 2 through 8, 2014. Island customers experienced a series of outages whose immediate origins lie in two separate streams of events. First, a shortage in Hydro generating resources caused the institution of a series of rotating outages. Second, as Hydro and Newfoundland Power, Inc. ("Newfoundland Power") were recovering from the circumstances leading to and the responses to these outages, a series of equipment and operations issues led to additional outages. The consequences of this second series of events included both widespread, uncontrolled outages and another series of rotating outages.

The shortage in Hydro's generating resources was caused by the unavailability, as January approached, of a number of its generation facilities which were out of service. At the same time, Hydro anticipated very high loads, reaching levels sufficient to threaten its ability to provide continuous service. Customers were asked to conserve energy after 2 p.m. on January 2. At about 4 p.m., rotating outages began. They continued until nearly 11 p.m. that day. Rotating outages resumed for a short time during the next morning's peak load period.

The equipment and operations related outages started on January 4th when Hydro experienced a major fire at one of its Sunnyside station transformers. At about 9 a.m., a variety of equipment failures and the operation of protective equipment caused the loss of generation and transmission capacity serving the Avalon Peninsula. Hydro worked through an extended series of equipment problems, variations in available generation, and operations activities, finally completing the bulk of immediate recovery efforts at around 3:30 p.m. on January 8.

Newfoundland Power reported outages to three-quarters of its retail customers during the two series of events that took place between January 2 and 8 of 2014. Some of them were for extended periods of time. Newfoundland Power attributed 15 percent of its customer outages to the capacity-induced rotating outages of January 2nd and 3rd, and 80 percent to the equipment related outages that followed and finally ended on January 8th. Winter storm conditions coinciding with these events independently produced the remaining 5 percent of outages for Newfoundland Power's retail customers.

B. Scope of Liberty's Engagement

The Newfoundland and Labrador Board of Commissioners of Public Utilities (the "Board") retained The Liberty Consulting Group ("Liberty") to study and report on *Supply Issues and Power Outages on the Island of Newfoundland Interconnected Electrical System*. This engagement followed the Board's determination, under the *Public Utilities Act*, R.S.N.L 1990, c. P-47, to conduct an investigation. The Board's objective in this investigation has been to:

> *complete a full and complete investigation into the issues that are to be identified by the Board on the supply issues and power outages that occurred on the Island Interconnected System in late December 2013 and early January 2014.*

The Board identified issues to be addressed in its investigation following a February 5, 2014 pre-hearing conference and consideration of a wide range of issues proposed by stakeholders, who provided written comments and participated in the pre-hearing conference. Board Order No. P.U. 3(2014) (the "February 19 Order") established the issues to be addressed by Liberty's study and reports thereon.[1]

Liberty was asked to investigate and complete an interim report including an explanation of the IIS events that occurred in December 2013 and January 2014, an evaluation of possible IIS changes to enhance preparedness for the 2014-2016 winter periods, and an examination of each utility's response to the outages. Liberty was also asked to provide a final report including an analysis of the events of December 2013 and January 2014, an evaluation of the adequacy of and reliability of the IIS up to and after the interconnection with the Muskrat Falls generating facility ("Muskrat Falls"), and an examination of customer communications and service enhancements for each utility.

Subsequently, in early October, the Board advised the parties that the remaining scope of the investigation would be dealt with in two phases, with the first addressing the adequacy and reliability of the IIS up to the interconnection with Muskrat Falls and the second dealing with the implications of the interconnection for adequacy and reliability. This report is filed in response to this Board direction.

1. The Interim Report

Liberty filed an interim report on April 24, 2014 (the "Interim Report"), which addressed the issues set out by the Board for that report. The overall scope of the Interim Report included an:

- Explanation of the IIS events that occurred in December 2013 and January 2014
- Evaluation of possible system changes to enhance preparedness in the short term (*i.e.*, 2014 through 2016)
- Examination of the response by the two utilities to the power issues and customer issues.

2. Purpose of this Report

The review leading to the Interim Report focused on outage causes and identification of measures that Hydro and Newfoundland Power could take to mitigate the risk of outages through the time when Muskrat Falls enters service as now scheduled. The Board's May 15, 2014 Interim Report focused on issues and actions that should be addressed to mitigate the potential for significant outages during the coming winter. The Board also asked Liberty to address longer

[1] **IN THE MATTER OF** *the Electrical Power and Control Act, 1994*, SNL 1994, Chapter E-51 (the "*EPCA*") and the *Public Utilities Act*, RSNL 1990, Chapter P-47,(the "*Act*"), as amended; and **IN THE MATTER OF** an Investigation and Hearing into supply issues and power outages on the Island Interconnected System.

term issues affecting reliability on the IIS. This report provides Liberty's assessment of the adequacy and reliability of the IIS up to the interconnection with Muskrat Falls. It discusses both immediate-term actions to address reliability for the coming winter and identifies opportunities for ensuring reliability of service in the longer term. It also provides our assessment of the progress Newfoundland Power has made in responding to the recommendations in the Interim Report and the directions in the Board's Interim Report.

3. Next Steps

Liberty continues to address reliability issues specifically raised by the introduction of Muskrat Falls. Liberty anticipates a spring 2015 report addressing the issues associated with Muskrat Falls and its link to the IIS.

C. Causes of 2014 Outages

Hydro and Newfoundland Power operate the equipment and infrastructure needed to provide service to IIS customers. Hydro provides the vast majority of the generation (supply) needed to produce electricity and the transmission needed to move that electricity to the areas where customers use it. Newfoundland Power operates most of the distribution facilities of the IIS, connecting end-use customers to the sources of electricity provided by Hydro's generation and transmission facilities.

Liberty continues to conclude, as we reported in the Interim Report, that the January 2014 outages stemmed from two differing sets of causes: (a) the insufficiency of supply (generation) resources to meet customer demands, and (b) issues with the operation of key transmission system equipment. Liberty found at the time that a continuing and unacceptably high risk of outages from such causes remains for the 2015-2017 winter seasons.

Liberty did not find then that Newfoundland Power operations or conditions contributed to the outages. That remains our view after completing the work leading to this report. The next paragraphs summarize the Hydro circumstances that we continue to believe lie at the root of the 2014 outages.

A shortage of generating capacity to meet customer demand produced outages that began on January 2, 2014. This shortage caused Hydro to request institution of a series of controlled, but substantial rotating customer outages. Liberty found that addressing the continuing risks of supply/demand imbalances would require adding resources and making sure that existing resources are available during winter peak load conditions. Liberty's Interim Report found, and Liberty continues to believe, that there exists a continuing and high risk of supply-related emergencies until Muskrat Falls and the Labrador-Island Link come into service. That time will be the winter of 2017/2018, at the earliest.

Liberty concluded in the Interim Report, and Liberty continues to believe, that transformer failure, protective relay design, circuit breaker malfunction, and operator knowledge issues all contributed to the January 2014 outages. Multiple equipment failures also underlay the January 2013 outages. Not only did equipment fail, but failures had consequence beyond what one would ordinarily expect to occur. In the second half of the period from January 2 through 8 of 2014, more widespread and uncontrolled outages resulted from Hydro equipment failures. These failures began with a fire at a major transmission system substation. Hydro ultimately experienced a series of major equipment failures at three of its terminal stations.

D. The Interim Report's Findings Regarding Newfoundland Power

The vast majority of the Interim Report's recommendations concerned Hydro. The 2014 outages resulted from Hydro's generation resources being unavailable and the failure of key transmission equipment on Hydro's system. Implementing rotating outages posed Newfoundland Power's major operational challenge during the January 2014 events. Conducting rotating outages in cold weather caused problems early in the process, but, as the outages continued, the Company was able to limit the duration of outages to the one-hour standard it sought to achieve. The Interim Report recommended that Newfoundland Power take advantage of the knowledge it gained in executing rotating outages, in order to facilitate the process of limiting the durations of any required rotating outages in the future.

Newfoundland Power made significant improvements between the 2013 and 2014 outages to increase the availability of representatives and information about outage condition and status. Liberty nevertheless did identify additional opportunities to pursue in continuing to improve performance. Liberty also recommended a formal joint effort by Hydro and Newfoundland Power to identify goals, protocols, programs, and activities that will improve operational and customer research, information, and communications coordination.

Liberty examined Newfoundland Power's progress in addressing the Interim Report's recommendations. Liberty also looked at other, longer term issues that may affect the performance of its transmission and distribution systems.

E. Response to Outage Events

The examinations leading to the Interim Report examined customer service accessibility and response and public and media communications in the context of the January 2014 events.

Liberty concluded in the Interim Report that Hydro and Newfoundland Power needed to work in a closely coordinated fashion during major events. Their goals should be common. The customer knowledge that forms the basis for their decisions should also be common. Particularly, their basis for making notifications to customers should be common, robust, and as objective as possible. The need to do so is strongly exhibited by a late request for customers to initiate conservation measures on January 2, 2014.

The principal recommendations in the Interim Report to address the communications issues at Hydro and Newfoundland Power include:

- Beginning the transition to a system that provides self-service (*i.e.*, without reaching a live representative) for reporting outages and emergencies, and inquiring about restoration status
- Conducting a joint Hydro/Newfoundland Power lessons learned exercise, involving the communications teams of both utilities, and seeking to develop a common set of plans for coordinating communications goals, processes, and interfaces for future major events

- Developing joint and individual outage communications strategies
- Conducting joint customer research designed to improve both Companies' understanding of customer expectations about outage information and conservation requests
- Developing clearer and more comprehensive advance notification procedures for Newfoundland Power customers
- Exploring additional communications channels (*e.g.*, two-way SMS text messaging or broadcasting options) for delivering outage status updates.

During Liberty's investigation in this phase Liberty reviewed the actions taken to address these recommendations.

F. Intercompany Coordination

The Interim Report also identified customer and intercompany communications as areas where greater efforts and more coordination between Hydro and Newfoundland Power would prove beneficial. This report examines efforts made in those areas. The needs Liberty identified include: (a) a number of operational data exchanges and protocols and procedures, (b) joint efforts to address communications with customers in advance of and during outages, and (c) undertaking structured, formal efforts to understand more about customer perceptions, attitudes, and expectations about service reliability and outage response.

G. Other Issues This Report Addresses

Liberty also examined for this report, as requested by the Board, the adequacy and reliability of Newfoundland Power's generation, transmission and distribution assets used to supply customers on the Island Interconnected System. The review included Newfoundland Power's reliability performance in recent years, the planning and design of its system, its asset management practices, its system operations, its management of outages and emergencies, including the plans, resources, and principal activities as intended and as actually implemented during the January 2014 events, and its communications with customers.

H. Study Approach and Methods

In this phase of the investigation, Liberty's study team first looked again at the nature of the events contributing to the outages and their immediate causes. Liberty did so to determine whether any new information or analysis would cause changes, deletions, additions, or emphasis on the causes determined during the review leading to Liberty's Interim Report. Liberty found nothing that would cause a change in our views. Second, we examined Newfoundland Power's progress in implementing the Interim Report recommendations involving it. Third, as requested by the Board, Liberty reviewed Newfoundland Power's system, approaches, resources, and activities associated with planning, design, and operation, in order to identify whether any opportunities for improving reliability exist.

Liberty conducted interviews with executives and managers responsible for the performance of the functions reviewed for the first time in this report, as part of Liberty's review of longer term plans, practices, resources, and actions to sustain service reliability. Liberty issued many formal requests for information, and reviewed the responses to them. Liberty again reviewed the reports that each utility filed in response to the Board's directions and we conducted interviews with Hydro and Newfoundland Power management about matters affecting them both (*e.g.*, customer communications and intercompany coordination issues identified in the Interim Report). After assembling a comprehensive set of factual findings, Liberty reviewed them and the tentative conclusions with both companies in order to give them an opportunity to identify errors or omissions of fact.

I. Liberty's Team

Liberty utilized essentially the same team that was used to conduct the review leading to the Interim Report, with one change. Liberty added a senior electric utility veteran whose management experience includes asset management and emergency planning. Each team member has spent 30 years or more in the industry. Liberty's president and one of the firm's founders, John Antonuk, led Liberty's examination. He received a bachelor's degree from Dickinson College and a juris doctor degree from the Dickinson School of Law (both with honors). He has led some 300 Liberty projects in more than 25 years with the firm. His work extends to virtually every U.S. state and he has performed many engagements for the Nova Scotia Utility and Review Board across a period of about ten years.

Mr. Antonuk has had overall responsibility for nearly all of Liberty's many examinations for public service commissions. His work in just the past several years includes: (a) examinations of overall direction of construction program, project management and execution, and operations and maintenance planning and execution at five major utilities, (b) assessment and monitoring of progress against major infrastructure replacement and repair programs, (c) multiple reviews of generation planning by electric utilities, and (d) use of risk assessment in the formation of electric utility capital and O&M programs, schedules, and budgets. Overall, he has directed more than 20 broad audits of energy utility management and operations, and more than 40 reviews of affiliate relationships (including organization structure and staffing) and transactions at holding companies with utility operations.
Mark Lautenschlager is a widely recognized expert in electricity transmission and distribution equipment and systems. His particular areas of expertise include electrical testing and maintenance, substation design and construction, forensic investigations of failed equipment, and technical training of electrical testing and maintenance technicians.

Mr. Lautenschlager has been conducting T&D reliability evaluations for Liberty for more than ten years. Most recently, he led Liberty's review of electric system operations in a management and operations audit of a utility engaged in a major program to address a series of weather-related, major outages. He focused on maintenance, construction, and root cause analysis. He has performed similar work for Liberty at nine major electric companies, including a number of Maine and Nova Scotia utilities. Before beginning his consulting career, he held substation maintenance and relay engineering positions in the electric utility industry, and ran a business focused on training electrical maintenance technicians and engineers, developing RCM-based substation maintenance programs, and performing forensic investigations of electrical equipment failures.

Mr. Lautenschlager is a registered professional engineer in Indiana, Ohio, and Pennsylvania, and holds a B.S.E.E. degree. He is a past president of the International Electrical Testing Association, and has been active in developing ANSI electrical equipment maintenance specifications.

Christine Kozlosky examined customer service and communications issues for this report. A nationally recognized utility customer service expert, she has worked with Liberty on many projects over 17 years. Her recent work with Liberty includes reviews of customer service and communications on four recent, broad management and operations reviews of major electric utilities, and on one project focusing specifically on customer service and communications. She has conducted many reviews of customer service and communications in the context of outage preparation and response, most recently in New England. She has also conducted base and follow-up reviews of outage communications at Nova Scotia Power as part of Liberty's engagement for the Utility and Review Board. This review examined storm response and communications.

Her earlier work in reviewing customer service and communications for Liberty includes four electric utilities, four natural gas utilities, and two telecommunications utilities. Ms. Kozlosky has been providing customer service performance benchmarking and performance improvement consulting since the early 1990s. She has conducted significant research into customer care best practices, process improvement, and performance benchmarking. She has a B.S. in Information & Computer Science from Georgia Institute of Technology.

Philip Weber was added to the Liberty team for the work for this report. He has over 35 years of professional experience in the electric utility industry specializing in reliability and maintenance of electric distribution systems, planning, and construction and project management. Phil managed the reliability and maintenance of the transmission and distribution system of a major Northeast electricity supplier PPL, where he produced major improvements in SAIFI and SAIDI performance.

Phil served on Liberty's team tasked with Development of Long-Term Electric & Gas Infrastructure Improvement Plan on behalf of NorthWestern Energy. He also served on Liberty's management reviews of East Kentucky Power Cooperative and Southwestern Public Service.

During a long career at PPL, Phil served as Project Manager in the Systems Operations Department, overseeing consolidation of the transmission operations function (69 kV and above) to a single office, while simultaneously managing the separation of the transmission operations function from the distribution operations (12 kV) function, and consolidation of regional offices. He also served as the System Maintenance Engineer, where he managed the reliability and maintenance of the transmission and distribution system, including the inspection and maintenance of 27,600 miles of overhead and 6,000 miles of underground circuits and related devices, managed the vegetation management program, administering an annual budget in excess of $50 million. He also had extensive experience in planning and managing storm response for the utility. Phil holds a B.S. in Industrial Engineering and a M.S. in Management Science from Lehigh University. He is a Registered Professional Engineer in Pennsylvania.

II. Planning and Design

A. Background

Newfoundland Power's[2] transmission system contains 103 lines having a total length of 2,055 kilometers, including eighty-three 66 kV transmission lines, 1,430 kilometers in length, nineteen 138 kV lines, 619 kilometers in length, and one legacy 33 kV line, six kilometers in length. Newfoundland Power's overhead transmission system contains about 27,000 poles, mostly pressure-treated wood poles, and some steel and laminated wood transmission poles. Forty-two percent of the transmission lines (870 km) are supported by single poles, while the remaining 58 percent (1,186 km) are supported by H-Frame structures. Four of Newfoundland Power's 66 kV transmission lines have underground sections, located where aerial construction is impractical, that have a total length of approximately three kilometers.

Newfoundland Power[3] has 306 distribution feeders with a total length of about 9,662 kilometers, including 210 – 12.5 kV feeders, 6,660 kilometers in length; 69 – 25 kV feeders, 2,458 kilometers in length, and 27 - 4.16 kV feeders, 544 kilometers in length. The Company's distribution system contains 294,722 wood poles.

Newfoundland Power's[4] distribution system is mostly (about 97 percent) overhead construction, with about 45 kilometers of mainline underground feeder cables, and about 65 kilometers of fused Underground Residential Distribution (URD) lateral cable loops fed by mainline feeders. Newfoundland Power typically installs underground distribution cable in locations where overhead construction is not practical due to property restrictions or congestion of equipment or buildings, such as the exiting of substations located in urban areas. URD installations are typically requested by a subdivision developer who wishes to provide underground distribution service to a housing development within the subdivision.

Newfoundland Power[5] has 130 substations with 149 transformers, not including voltage step-up substations at generation facilities, with transformers ranging in size from 1.0 MVA to 50 MVA. Some of the substations have multiple transformers and multiple feeders serving large numbers of customers, while others have a single transformer and a single feeder serving few customers.

1. Reliability

Liberty's examination of planning and design emphasized how reliability issues affect identification of needs to meet current and future system needs. Liberty therefore began with a review of recent-year reliability metrics for Newfoundland Power's transmission and distribution systems, in order to determine its base levels of performance and to identify the impacts that major events in recent years have had on that performance. This baseline review also sought to disclose any particular areas of concern or emphasis for Liberty's review of transmission and

[2] Responses to RFIs #PUB-NP-076 and 241.
[3] Responses to RFIs #PUB-NP-076 and 242.
[4] Response to RFI #PUB-NP-241.
[5] Responses to RFIs #PUB-NP-145, 244 and 274.

distribution management and operations. Electric utilities generally measure reliability in several ways, which include:

- The number of customer interruptions (CIs)
- The number of customer minutes of interruptions (CMIs)
- The system average interruption duration index (SAIDI)
- The system average interruption frequency index (SAIFI).

2. Planning

Transmission and Distribution Systems Planning activities identify and plan to fill needs for capital transmission, substation, and distribution projects required to provide the capacity to accommodate load growth and stability and to maintain system condition and reliability at acceptable levels. Planning duties include conducting load flow and other studies, developing energy and peak demand forecasts for business and technical reasons, and assisting system operators in addressing real-time system operations issues. Liberty examined the planning organization, criteria for planning capacity and reliability projects, and provision of support for Energy Control Center activities.

3. Design

Transmission and distribution electric power system designs need to balance cost, reliability, and load growth needs. Newfoundland Power equipment should be designed to withstand expected loads and known fault current levels. Transmission and distribution line conductor load ratings should employ industry accepted standards. Poles and lines should be designed with sufficient strength to withstand physical loads caused by expected high winds and heavy icing. Lightning arresters should be installed on distribution feeders and substation equipment to minimize lightning-caused damage. Animal guards should be installed to minimize animal-caused damage and customer interruptions. Liberty reviewed Newfoundland Power’s design standards and criteria, its use of sectionalizing, Supervisory Control and Data Acquisition (SCADA), and overvoltage and animal protection for comprehensiveness and sufficiency in meeting customer needs.

4. Protection and Control

Protective relays quickly trip circuit breakers to clear line, bus, and transformer faults, in order to minimize equipment damage and to maintain system stability. Utility transmission systems typically use sophisticated impedance-type distance measuring relay schemes. They supplement them with backup secondary relay schemes to allow tripping following primary relaying or circuit breaker malfunction. Utility distribution systems typically use overcurrent relays or electronic reclosers to protect distribution-voltage equipment and feeders. Single-function electromechanical impedance and overcurrent relays have been used for about 90 years. They sometimes prove inaccurate and they require periodic testing to verify operation. Replacing electromechanical transmission relays with electronic relays has become increasingly common in recent decades. The use of programmable multifunction relays reflects the most recent trend. These relays offer high accuracy, do not require much testing, and provide relay status and fault current data. They can also provide breaker control via a SCADA system.

Liberty reviewed Newfoundland Power's protective relay scheme design philosophy, maintenance practices for electromechanical relays, the extent of modernization of the relay scheme with programmable relays, and how relay malfunctions are investigated.

B. Chapter Summary

1. Reliability

Newfoundland Power has in recent years made substantial improvements in its transmission and distribution systems. Focused rebuild and modernization projects have supplemented regular maintenance and vegetation management practices to produce steady improvement in the performance of its aged electric systems. After excluding the impacts of major outage events, the amount of interrupted per customer experiences has fallen from 5.7 to 2.2 hours between 1999 and 2013. The number of interruptions per customer fell during this period from 4.72 to 1.71. Recent performance under these metrics has been better than the average of other Canadian utilities over the last few years. Nevertheless, Newfoundland Power has opportunities to improve distribution system performance, which accounted for about 85 percent of outage durations metrics in 2013. Newfoundland Power should consider applying more capital for distribution system rebuilds and in installing more downstream reclosers on feeders.

2. Planning

Newfoundland Power's system planning organization is appropriately staffed and uses capacity planning criteria that are consistent with good utility practice. Planning engineers and technologists assist asset management personnel to identify and prioritize capital projects for rebuilding and modernizing the electric systems. The organization provides system operations personnel with the load flow and other studies needed to operate its systems. Since 2013, system planning senior management has been working with their counterparts at Hydro to examine reliability, system contingency and restoration planning, generation availability, and peak load management preparedness. Newfoundland Power should, however, change its prioritization practices for proposed projects by weighting scores under its selection criteria and by including a comparison of project costs versus anticipated reductions in customer interruption numbers and minutes.

3. Design

Liberty reviewed Newfoundland Power's design standards and criteria, its use of sectionalizing, its Supervisory Control and Data Acquisition (SCADA), and its overvoltage and animal protection practices for comprehensiveness and sufficiency in meeting customer needs. Liberty found them to be appropriate.

4. Protection and Control

Organization and staffing of the relay group matches needs. Newfoundland Power's protective relay scheme designs comport with those of similar utilities. Newfoundland Power has been replacing obsolete transmission system electromechanical with microprocessor relays that improve accuracy, flexibility, and monitoring capability, while reducing maintenance requirements. Newfoundland Power investigates relay malfunctions and coordination issues.

Liberty found, however, that Newfoundland Power does not: (a) formally document standard relay scheme designs and their operation, and (b) periodically test operate ("exercise") its relay-to-circuit breaker operation. It does verify operation when commissioning equipment, investigating operating issues, and when it operates breakers by the SCADA system.

C. Findings

1. Reliability - T&D System Performance Overview

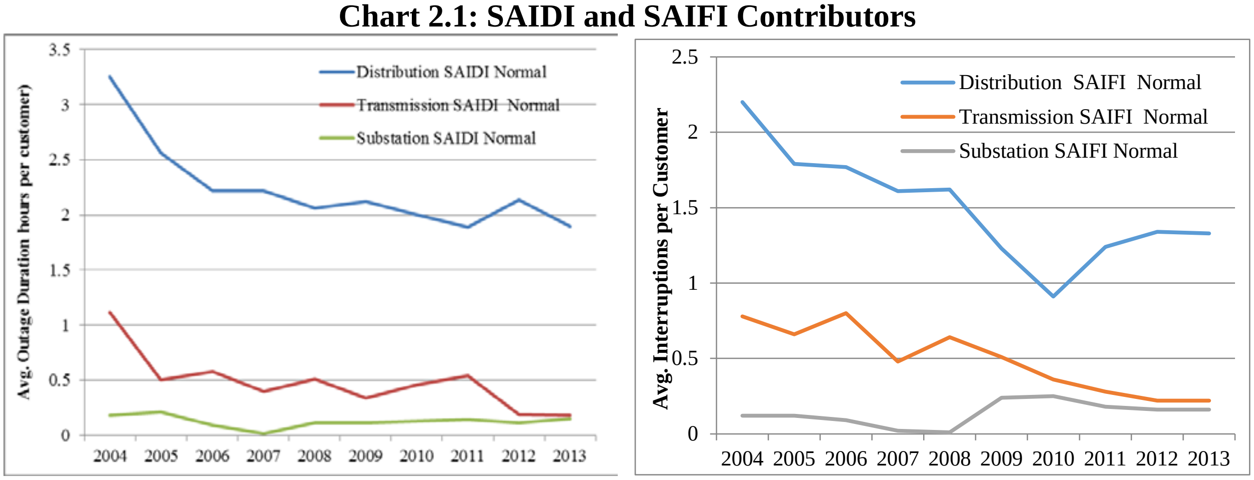
Consistent with usual electric utility practice, Newfoundland Power[6] tracks the performance of its transmission and distribution systems using measures of outage frequency and duration:

- For frequency, System Average Interruption Index (SAIFI)
- For duration, System Average Interruption Duration Index (SAIDI), measured in minutes.

Newfoundland Power also tracks numbers and minutes of customer interruptions (CIs and CMIs). Newfoundland Power also recently began to use the new Canadian Electricity Association (CEA) metrics of customer interruptions per kilometer (CIKM) and customer hours of interruption per kilometer (CHIKM). These metrics highlight performance on shorter feeders that serve denser populations.

Newfoundland Power[7] has experienced significantly improved SAIDI and SAIFI metrics, measured after excluding major events, as the next chart demonstrates. Its performance under these two metrics exceed Canadian Electricity Association composite measures, although direct comparisons of performance are difficult, given differences among participating utilities. The next charts, however, show that Newfoundland Power's overhead distribution system, compared to its transmission system and it substations, has caused by far the most interruptions, measured by both frequency (SAIFI) and duration (SAIDI).

Chart 2.1: SAIDI and SAIFI Contributors

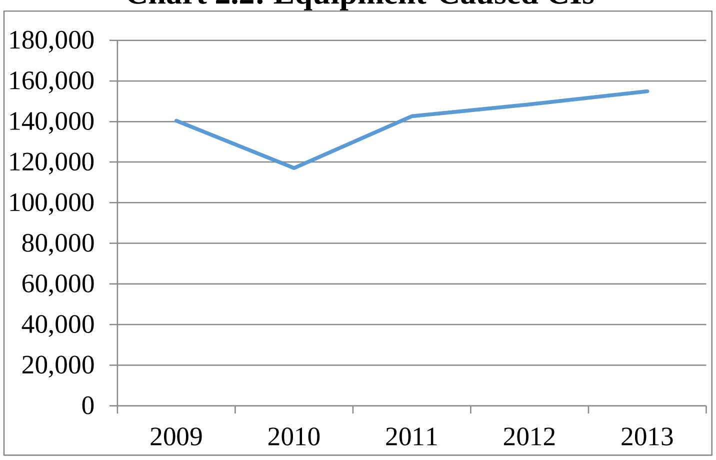


[6] Responses to RFIs #PUB-NP-061 and 065, and Newfoundland Power's 2015 Capital Budget Application.
[7] Responses to RFIs #PUB-NP-308.

2. Reliability - Primary Causes of Customer Interruptions

Newfoundland Power's outage cause codes follow Canadian Electricity Association guidelines.[8] "Equipment failures" have been the predominant outage cause, accounting for 0.63[9] of the Company's 1.71 SAIFI[10] in 2013 and 25 percent[11] of customer interruptions. The next chart shows, despite reduction and eventual leveling of SAIFI in recent years, that equipment-caused interruptions have increased, driven principally by primary conductor, insulator, and cutout failure.[12] Primary[13] conductor failures generally result from winds and severe ice. They break older ACSR (aluminum conductor-steel-reinforced) conductors having steel cores weakened by salt corrosion. Insulator and cutout failures generally result from the physical failure adhesive binding insulators to steel parts. Recloser failures generally result from loss of oil or water entry caused by corrosion. A Newfoundland Power initiative replaces old steel-reinforced conductors with aluminum-alloy-conductor concentric-lay-stranded conductors, and replaces insulators and reclosers. Failures of Newfoundland Power[14] equipment contributed only marginally (6 percent of outage time) to outages during the January 2014 events.

Chart 2.2: Equipment-Caused CIs



3. Reliability – Sectionalizing Devices

Installing automatic circuit reclosers on distribution feeders downstream from substations can provide substantial reliability rewards. These reclosers sectionalize a faulted feeder section from other sections. Newfoundland Power[15]currently has twenty-six automatic circuit reclosers downstream from substations on seventeen distribution feeders. Newfoundland Power plans by the end of 2014 to add 14 additional reclosers to the few now remotely controlled via SCADA. These installations primarily seek to address cold load pickup issues occurring during the rotating feeder outages of January 2014.

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[8] Response to RFI #PUB-NP-154.
[9] Response to RFI #PUB-NP-286.
[10] Response to RFI #PUB-NP-287.
[11] Response to RFI #PUB-NP-288.
[12] Response to RFI #PUB-NP-288.
[13] Liberty meeting with Newfoundland Power on September 19, 2014.
[14] Response to RFI #PUB-NP-037.
[15] Responses to RFIs #PUB-NP-078, 079, 289, and Order No P.U. 14 (2014).

Newfoundland Power protects lateral feeders which are tapped off of the mainline feeders with fuses, except for very short and heavily loaded feeders and single and two phase lateral feeders. Fusing prevents proper coordination with mainline (trunk) feeder protection. Newfoundland Power monitors these cases, and authorizes capital projects that reduce single-phase loading.

4. Planning - System Planning Organizations

The Transmission and Substation Planning Engineer directs annual forecasts of peak demands and load factors, which Hydro uses as well. The Planning Engineer directs or assists with medium- and long-term transmission planning.[16] The Supervisor of Engineering and Standards, with assistance from Regional Distribution Engineers, directs medium- and long-term distribution planning. This Supervisor also directs real-time distribution system operational analyses necessary for daily System Control Center operations. The Planning Engineer and the Supervisor also assist in performing technical and financial studies of proposed capital projects.

The Vice-President, Customer Operations and Engineering approves capital projects for inclusion in the annual capital budget, in consultation with other executives. The Vice-President works directly with the Manager of Engineering, Manager of Operations, Regional Managers, and senior engineers responsible for the transmission, substation, and distribution asset classes in the development of the annual capital budget.

Planning personnel also conduct the real-time operational analyses of the transmission system necessary for daily System Control Center operations. A Senior Engineer, two Engineering Technologists, and engineering work-term students support planning efforts. The Supervisor, Distribution Engineering Standards and the Manager, Revenue and Supply, support various planning activities.

5. Planning – Transmission Capacity Additions

Transmission and distribution planning criteria[17] must align with those of the Canadian Electricity Association (CEA). Newfoundland Power designs and constructs transmission and distribution systems so as to support forecasted peak flows without: (a) exceeding normal ampacities (thermal limitations), (b) violating voltage criteria, and (c) exceeding equipment fault duty (short circuit) ratings. The Company, however, allows limited equipment operation above planned ampacities under emergency conditions or when the systems are out of normal configuration.

Newfoundland Power[18] prepares annually five-year capital plans and budgets. These capital plans include projects designed to resolve MW and MVAR flow and voltage restraints on transmission lines and substation transformers. Newfoundland Power conducts analytical load-flow analyses, using a computer model that simulates system performance across the planning horizon, considering anticipated winter peaks and Newfoundland Power generation availability. Newfoundland Power develops solutions if future operating conditions are expected to produce

[16] Responses to RFIs #PUB-NP-155, 157, and 191.
[17] Responses to RFIs #PUB-NP-155 and 157.
[18] Responses to RFIs #PUB-NP-147, 148, 155, 269, and 272.

violations of design and equipment rating criteria. Annual load growth of 1.7 percent has required some distribution substation and feeder construction or upgrades, but the most recent transmission line construction occurred some 10 years ago.

The 2012[19] winter peak forecast produced a maximum peak loading level on a transmission line at less than 65 percent of normal winter rating, with most lines loaded at even lower levels. Modeling under the 2014/2015 winter peak forecast shows all transmission system transformers operating within nameplate ratings. Newfoundland Power therefore plans no transmission line or transformer capacity upgrades.

6. Planning – Distribution Capacity Additions

Annual five-year capital project plans address anticipated technical transformer and feeder issues resulting from load growth and other causes. Newfoundland Power conducts annual distribution load growth and voltage analytical studies, based on transformer and feeder ampacities, historical demand levels, and anticipated customer load additions. The Company also considers the results of short-circuit studies and voltage level studies (conducted every two to three years) and protective device coordination studies when the system is changed.

The 2014/2015 winter peak forecast would place eight distribution substation transformers above nameplate ratings. The Company has procedures to monitor these transformers if they are operated in excess of ratings and plans upgrades, added transformers, or load transfers to address the observed capacity insufficiencies. Newfoundland Power will have also completed capacity upgrades at Hardwoods, Bay Roberts, and Marble Mountain Substations in preparation for the 2014/2015 winter peak. Forecasted 2014/2015 winter peaks will not require any distribution feeder to operate in excess of its winter rating. Only a few feeders currently approach 100 percent of ratings.

7. Planning - Reliability Improvement

Newfoundland Power[20] considers reliability, rather than a need to serve new load, the primary driver of capital work, accounting for an estimated fifty percent of each annual capital budget. The Asset Management groups identify the need to improve the condition and reliability of aged T&D equipment and, working with various planning personnel, develop solutions based on merit, least cost alternatives, and priorities. However, the process for assessing reliability projects uses no scoring process. Other companies Liberty has observed use a comparison of project cost versus expected numbers of customer interruptions or customer minutes of interruption. Newfoundland Power relies on engineering judgments that consider reliability metrics, inspection results, and condition and event assessments.

Newfoundland Power implemented in 1998 a Distribution Reliability Initiative to address a number of reliability issues. Identification of potential projects begins with an annual identification of the 15 worst performing feeders. Five-year trends in SAIDI, SAIFI, and customer minutes of interruptions determine these 15 feeders. Other structured programs include:

[19] Responses to RFIs #PUB-NP-274, 275, and 276.
[20] Responses to RFI #PUB-NP-272.

- Rebuild Distribution Lines Projects (introduced in the 2004 capital budget application and updated in 2013)
- Long-term Transmission Line Rebuild Strategy (implemented in 2006 and included in capital budget applications) to identify aging transmission line infrastructure for rebuild, based on physical condition, risk of failure, reliability statistics and potential failure impacts on customers.
- Long-term Substation Strategic Plan (implemented in 2007 and included in capital budget applications) to deal with aging substation infrastructure in a manner that is based on criteria similar to the Transmission Line Rebuild Strategy.

8. Planning - Inter-Utility Communications

Oversight[21] of matters of joint concern related to system reliability falls under the Inter-Utility System Planning and Reliability Committee. This committee is made up of senior operations and engineering management of both Newfoundland Power and Hydro. The Committee meets twice a year to consider matters related to system reliability, system contingency and restoration planning, generation availability, and peak load management preparedness. In 2013 the two companies increased the work of the Joint System Planning Subcommittee. Planning engineers from both utilities review Newfoundland Power's annual energy and winter peak demand forecast.

The utilities keep each other informed of major transmission and transformer capacity additions and, on occasion, conduct joint transmission and terminal station capacity constraint studies. Newfoundland Power, however, has not been able to conduct a formal analysis of the effect of the Labrador-Island Link on its transmission system because it is not privy to Hydro's operations and stability studies related to integration of Muskrat Falls that may have been conducted by Hydro.

9. Design - Transmission Line Standards and Criteria

Newfoundland Power[22] designs, builds, and rebuilds its transmission lines in accordance with the vertical and horizontal clearance requirements specified in Canadian Standards Association Standard C22.3 No. 1 Overhead Systems. Newfoundland Power's transmission and vegetation inspection programs identify any deficiencies with respect to line clearance requirements. The Company employs transmission line conductor ratings designed to allow the availability of full ampacity for each line, under normal and emergency conditions and various ambient temperatures, without causing conductor damage or excessive sag. Newfoundland Power designs conductors on the basis of[23] continuous winter (0° C) and summer (25° C) load current ratings, under specific air temperature and wind conditions, based on limiting conductor temperatures to 75° C. Greater temperatures could cause conductor damage and excessive conductor sag. Newfoundland Power does not employ "emergency" ratings for transmission line conductors, but allows ratings to be exceeded on a case-by-case basis when ambient air temperature and wind speed conditions allow for higher loading.

[21] Responses to RFIs #PUB-NP-002 and 170.
[22] Response to RFI #PUB-NP-282.
[23] Response to RFI #PUB-NP-146.

The ability to transfer loads from one transmission line to another line improves reliability and system stability when transmission equipment is not in service. Newfoundland Power does not have a policy specifically requiring full N-1 contingency redundancy (no customer interruptions for the loss of a line at peak load). Nevertheless, more than half of the transmission system provides such redundancy.[24]

About fifty-four percent[25] of Newfoundland Power's transmission system, mostly serving urban areas, is "looped." Looping serves substations by at least two lines, thus providing redundancy. The Company's four sections of underground transmission lines have full redundancy. About twenty-two percent of its transmission system serves substations radially. Diesel, gas turbine, or hydro backup generators are available to serve some or all loads at a substation during radial line maintenance outages. About twenty-four percent of its transmission system, mostly serving rural areas, serves substations radially without any backup generation capability.

Newfoundland Power[26] directly controls and monitors 94 of its 103 transmission lines from its System Control Center via its SCADA. Eight of the remaining nine are controlled by operating SCADA controlled breakers on lines that feed the substations supplying those lines.

10. Design - Transmission Line Fault, Overvoltage, and Galloping Protection

Newfoundland Power protects transmission lines with relay-controlled circuit breakers and automatic sectionalizing switches. Virtually all[27] transmission lines employ protective relays operating substation circuit breakers to clear faults. The remaining four transmission lines have automatic sectionalizing switches (motor-operated air-break switches) at substations.

Preventing transmission line equipment damage and faults caused by overvoltages is a function of line design, grounding, relaying, and the use of lightning arrestors. Lightning is not now an issue for Newfoundland Power. To minimize transmission line lightning-caused damage the overhead ground wires on 138 kV transmission lines[28] have been extended 800 meters out from substations and lightning arresters have been installed at its 66 kV transmission line underground cable terminations. It protects its 138 kV and 66 kV steel structures with grounded lightning rods. Newfoundland Power also uses instantaneous relay/breaker tripping to minimize damage caused by lightning.

Wind and ice-caused conductor oscillation (so called galloping) can damage transmission line hardware. Newfoundland Power[29] installed interphase insulated spacers on the few transmission line sections that have experienced damaging conductor galloping.

[24] Responses to RFIs #PUB-NP-145 and 155.
[25] Response to RFIs #PUB-NP-061 and 145.
[26] Response to RFI #PUB-NP-245.
[27] Response to RFI #PUB-NP-149.
[28] Response to RFI #PUB-NP-281.
[29] Response to RFI #PUB-NP-284.

11. Design - Feeder Standards and Criteria

Newfoundland Power[30] designs, builds, and rebuilds its distribution lines in accordance with the vertical and horizontal clearance requirements as specified in CSA Standard C22.3 No. 1 Overhead Systems. Newfoundland Power's transmission, distribution and vegetation inspection programs identify any deficiencies with respect to the clearance requirements.

Newfoundland Power performs distribution feeder conductor planning and determines operating ratings under the same ampacity considerations and temperature conditions that apply to transmission conductors.

Newfoundland Power also considers in winter planning ratings the amount of initial current occurring when a feeder is restored. This "cold load pickup" can be twice the winter peak demand load. However, the cold load pickup current flowing when a feeder breaker is closed can be reduced to about one 1.33 times winter peak demand. A recloser, located downstream from the substation, can be opened so as to pick up no more than about two-thirds of the feeder load during restoration.

Newfoundland Power has normal and emergency ratings for its aerial and underground distribution cables. Underground ratings depend on conditions (direct buried, run in conduits, number of circuits at a location, insulation type, ambient earth temperature, and thermal resistivity). Newfoundland Power allows aerial and underground cables to operate at twice normal ratings for up to one hour (for cold load pick up) and for longer times at "emergency ratings."

Load transfer capability is supported on 249 of Newfoundland Power's[31] 306 distribution feeders. The 249 feeders have line ties outside of substations to other adjacent feeders. Line ties are not practical for the remaining fifty-seven feeders, which lie in rural areas where no adjacent feeders are available. For underground primary feeders, Newfoundland Power generally provides redundant capacity if an underground primary feeder cable fails. Newfoundland Power's underground residential distribution (URD) laterals tapped off of mainlines are open-looped at normally open tie switches. This configuration reduces the time required to restore service to customers on a half loop when a cable section fails.

12. Design - Distribution SCADA

Newfoundland Power[32] operates SCADA control and monitoring in substations serving about 60 percent of its distribution feeders and it has 26 automatic circuit reclosers (downstream from substations) on 17 of its 306 distribution feeders. Its 2015 Capital Budget Application included a two-year project to replace the existing SCADA system because the vendor of the current system no longer supports it. Newfoundland Power will solicit proposals from vendors who supply smaller utilities. The new system will be capable of advanced distribution management functions

[30] Response to RFI #PUB-NP-282.
[31] Response to RFI #PUB-NP-246.
[32] Response to RFIs #PUB-NP-077, 078, 079, and 149.

including eventual interfaces with the Geographic Information System (GIS) and to a new commercial Outage Management System (OMS).

13. Design - Distribution Fault and Overvoltage Protection

Newfoundland Power has fused all of its lateral feeders, except for short taps and heavily loaded taps, where fuses cannot be coordinated with the mainline feeder protection.

Based on the "cold load pick up" issues Newfoundland Power[33] experienced restoring heavy loaded feeders during the January 2014 rotating feeder outages, it identified that installing additional feeder sectionalizing, via fourteen SCADA-controlled downstream automatic circuit reclosers on heavily loaded feeders, would minimize recurrence of that problem. Probably as importantly, these new reclosers should improve both SAIDI and SAIFI metrics for those feeders. The automatic reclosers provide better isolation of faults, more timely restoration of feeders, and more efficient use of line crews. The Company plans to have the fourteen additional downstream feeder reclosers installed by the end of 2014.

Newfoundland Power[34] installs lightning arresters on all new distribution pole-mounted transformers and on downstream voltage regulators and reclosers, and, since 2003, has been installing arresters on existing devices under its distribution rebuild capital projects. It also installs arresters on underground cable terminations supplying pad mount transformers.

14. Design - Line Strength Criteria

The ability of a transmission or a distribution line to withstand expected high winds and icing occurring during storms depends substantially on pole strength or tower design and span length. Newfoundland Power[35] constructs and rebuilds its overhead transmission and distribution lines to exceed the latest Canadian Standards Association (CSA) overhead systems wind and ice load criteria. It uses using larger class poles, shorter line spans, and additional guying. These standards require constructing overhead transmission and distribution lines to withstand at least 92 kilometers per hour wind (a force of 400 Pascals), 12.5 mm of radial ice when wind and ice have been "heavy," and 19 mm for "severe" radial ice.

Since 2001, Newfoundland Power has been constructing and rebuilding its overhead T&D systems in the Avalon and Bonavista Peninsulas consistently with the "severe" criterion. Much of Newfoundland Power's overhead systems were constructed under previous CSA criteria; it cannot report exactly how much. However, the long practice of exceeding the CSA criteria, gives the Company confidence that the number of facilities that do not meet current design criteria is relatively low.

15. Design – Substation Load Transfer

The ability to transfer loads from one substation transformer to another transformer improves reliability when substation equipment is not in service. Some Newfoundland Power transformers

[33] Response to RFI #PUB-NP-289.
[34] Response to RFI #PUB-NP-281.
[35] Responses to RFIs #PUB-NP-242 and 243.

have the capacity to accept loads from other transformers. Twenty-nine substations have more than one power transformer, and contain twenty-four sets of multiple transformers sized to provide N-1 contingency (no customer interruptions for loss of a transformer in a set), except under peak winter loads. Thirteen of the twenty-nine multiple-transformer substations are located in the more densely populated St. John's area. Newfoundland Power also maintains four portable substations to bypass fixed substations as required. The substations contain by-pass switches to limit the length of customer outages occurring when a substation circuit breaker or recloser fails, or when maintenance work is conducted.

16. Design - Substation Transformer Operating Ratings

Under expected conditions, an electric utility should seek as far as practicable to retain the capacity to operate substation equipment within the load versus temperature ratings as indicated by the equipment manufacturers. Newfoundland Power[36] plans and operates its substation equipment within manufacturer's ratings under expected peak load conditions. When the distribution system is out of normal configuration (*e.g.*, following a transformer failure), the Company allows circuit breakers and other transformers to operate temporarily in excess of normal ratings (within IEEE C57.12 temperature limitations). This exception can permit continuity in customer service until deployment of a mobile substation is in place, or there is a return to normal configuration.

Newfoundland Power[37] operates its power transformers according to its *Power Transformer Loading Guidelines.* The Company normally allows its substation transformers to operate up to 105 percent of nameplate rating during the summer. The Company also allows, under short-term emergency conditions, transformers to operate up to 130 percent, and even higher, with on-going scrutiny of load and temperature, and by limiting load, loading time periods, and transformer temperatures based on accepted "Loss of Transformer Life" curves derived from ANSI/IEEE Loading Guide C57.12.30-1981.

17. Design - Animal Protection

Newfoundland Power[38] reports that animals have minimal effect on its system reliability performance. Less than 1 percent of 2013 customer interruptions were caused by animals and birds. Nevertheless, Newfoundland Power reported that large birds and small animals occasionally cause short circuits in distribution reclosers, metering tanks and station service transformers. These instances have often severely damaged equipment. Based on success at other utilities with modern methods of animal protection, Newfoundland Power began installing devices on its substation equipment and distribution transformers in the mid-2000s. The Company found that installing insulated coverings, guards and insulated leads have been effective in preventing animal-caused damage and outages and therefore includes "varmint protection" as one of the refurbishment items completed under its annual Substation Refurbishment and Modernization capital project

[36] Responses to RFIs #PUB-NP-145 and 146.
[37] Response to RFI #PUB-NP-064E, page 1488.
[38] Response to RFI #PUB-NP-283.

18. Design - Substation Overvoltage Protection

Preventing substation transformer and bus damage and faults caused by excessive transient voltages requires the use of lightning arrestors. Newfoundland Power[39] equips its substation power transformers with lightning arrestors on both the high voltage and low voltage sides, it grounds its substation bus structures, and it protects its 138 kV and 66 kV steel structures with grounded lightning rods.

19. Design - Fault Duty Studies

Fault currents at various locations on transmission and distribution systems can increase when system changes are made, such as when additional generation is installed, circuits are paralleled, or transformers are changed. Newfoundland Power[40] conducts short-circuit studies every two or three years and when system changes are made to verify that none of its transmission or distribution circuit breakers or feeder reclosers will be exposed to fault currents in excess of fault-duty ratings. Newfoundland Power has replaced twelve circuit breakers since 2004 because of fault-duty limitations.

20. Design - Geographic Information System (GIS)

A Geographic Information System (GIS) is a digital record of a utility's equipment locations and electrical connectivity, and usually includes other important equipment data critical for operating the system, for conducting engineering studies, and for managing equipment repairs and maintenance. Newfoundland Power[41] implemented a GIS only recently, in 2013. Its GIS displays on computers equipment data and locations of primary distribution feeders, streetlights, and poles, based on data collected from its distribution model in the 1990s, on the Streetlight Management System, and on a pole survey Bell Aliant pole database from the 2011 pole sale to Newfoundland Power. Newfoundland Power has processes in place for reviewing the accuracy of the data and for updating the GIS when new equipment is installed in the field.

21. Protective Relays - Designs

Newfoundland Power[42] has no formal protective relay scheme design criteria document describing its standard design philosophies. Its practice, however, for transmission line and circuit breaker protection includes the use of a single relay protection scheme with backup from remote, back-line protection. It uses three types of protection schemes for its transmission lines: (a) line current differential protection schemes with fiber optic communication, (b) distance or impedance protection, and (c) overcurrent protection with phase and ground fault elements. Current differential protection protects transmission lines less than ten kilometers in length. Distance protection exists for 138 kV looped transmission lines, with distance or overcurrent protection applying on other transmission lines.

Newfoundland Power is in the process of modernizing the technology used in its protection schemes. This process has resulted in increased use of distance protection and a decreased use of

[39] Response to RFI #PUB-NP-281.
[40] Response to RFI #PUB-NP-148.
[41] Response to RFI #PUB-NP-278.
[42] Response to RFI #PUB-NP-279.

overcurrent protection as the primary method. Newfoundland Power is also implementing expanded functionality of programmable relays in new relay schemes to provide multiple protection schemes. As appropriate, it also uses overcurrent protection as a backup to differential and distance relaying schemes. Finally, the Company is modernizing breaker failure schemes to provide backup when breakers fail to operate.

For its substation protection, Newfoundland Power uses relaying with three protection zones, high voltage (66 kV and 138 kV) bus protection, power transformer protection and low voltage bus protection. The protection scheme used varies depending on the number of transmission line terminations and transformers.

Newfoundland Power provides differential protection schemes for high voltage buses which have two or more circuit breaker controlled transmission lines. It protects its other high voltage buses by remote, back-line transmission line protection. High voltage buses with three or more transformers have high voltage bus-tie breakers to improve fault clearing selectivity and to improve service reliability. For power transformers with capacities greater than a 7.5 MVA base rating, Newfoundland Power uses a differential current protection scheme along with phase and ground overcurrent protection. In substations where there is no high voltage breaker, the transformer protection scheme operates a high-speed ground switch which trips back-line transmission line protection. Power transformers rated 7.5 MVA and lower are protected by power fuses.

Newfoundland Power uses phase and ground overcurrent protection to protect distribution feeders. It blocks the instantaneous tripping function after the first trip, in order to allow time for downstream fuses to operate before the feeder trips the second time.

22. Protective Relays – Maintenance, Testing, and Replacement

An Engineering Technologist responsible for substation maintenance work planning schedules relay testing. An Asset Maintenance Coordinator monitors substation inspection and preventative maintenance activity, scheduling and tracking testing. The Superintendent System Control and Electrical Maintenance directs substation inspections and preventative maintenance activity.

Newfoundland Power[43] has since 1998 been systematically replacing electromechanical relays with new micro-processor programmable relays. Protection and Control Engineers and Engineering Technologists review all updated relay schemes to verify conformity with design criteria. The new relays comprise micro-processor controlled, programmable relays. One programmable relay can replace multiple electromechanical ones. Self-diagnostic capability and programmable monitoring capacity combine to improve the reliability of protection, and increase efficiency in the use of field personnel. Newfoundland Power[44] spent $10.1 million replacing old electromechanical relays from 2008 through 2012.

[43] Responses to RFIs #PUB-NP-075, 279 and 280.
[43] Response to RFI #PUB-NP-075.

Newfoundland Power[45]tests, adjusts, or replaces its electromechanical relays on five-year cycles. Newfoundland Power does not formally periodically test operate ("exercise)" relay-to-circuit breaker operation, but verifies operation when commissioning equipment or investigating operating issues. It also operates breakers via the SCADA system. The programmable relays do not require scheduled testing. Their self-diagnostics can generate alarms remotely monitored through the Company's SCADA system. Newfoundland Power targets a completion rate of 70 percent for relay maintenance items. It has maintained that rate, albeit with substantial acceleration, in the past several years. Newfoundland Power[46] investigates relay malfunction and coordination issues. The SCADA system time-tags events in a manner that permits analysis of event sequences. Engineering Technologists and Electrical Engineers who specialize in protection and control systems review SCADA events logs to verify the appropriateness of events sequences associated with protection schemes.

D. Conclusions

<u>Reliability</u>

2.1. T&D reliability has substantially improved since 1999 and has recently remained stable overall.

SAIFI and SAIDI metrics have substantially improved. Performance has been better than Canadian Electricity Association (CEA) composite measures since 2005 for SAIDI and since 2009 for SAIFI. Newfoundland Power employs a suitable range of processes and programs that address equipment conditions. Effective maintenance practices and infrastructure-improvement capital programs have contributed to improved reliability. Newfoundland Power designs overhead lines to weather standards exceeding CSA standards, performs regular inspections, and addresses worst performing feeders.

The Company has engaged in a number of specific initiatives to improve reliability performance, including its Distribution Reliability Initiative, Rebuild Distribution Lines Project, Substation Refurbishment and Modernization Strategy, and Transmission Rebuild Strategy. Newfoundland Power's capital expenditures for its transmission, substation, and distribution rebuild and modernization strategies have steadily increased since 2004. Expenditures in 2014 remain substantial.

2.2. The large contribution that the distribution system makes to outages and the number of equipment-caused failures indicate room for further improvement in reliability. (*Recommendation #2.1*)

The Company's transmission system and substations contributions have contributed only in small measure to SAIFI and SAIDI measures. Excluding major outage events, equipment failures have caused the greatest number (25 percent, and increased marginally since 2010) of customer interruptions related to the distribution system. Primary conductor, insulator, and cutout failures were the greatest causes of equipment-caused CIs. The comparatively large number of distribution system-caused customer outages can be addressed through the use of additional

[45] Responses to RFIs #PUB-NP-075, 200, 233, and 234.
[46] Response to RFI #PUB-NP-200.

downstream feeder reclosers and through increasing the priority on the *Rebuild Distribution Lines Project* when prioritizing capital projects. Improving the condition of older distribution feeders particularly by upgrading conductors, insulators, and cutouts will address conditions that have contributed the most to the Company's equipment-caused failures.

2.3. Newfoundland Power focused on worst performing feeders for some time, but has recently ceased committing resources to them despite the fact that such feeders still exhibit disproportionately high outage metrics. *(Recommendation #2.2)*

Newfoundland Power identifies worst performing feeders, but has not addressed any under its Distribution Reliability Initiative since 2011. Since the 1998 inception of a process for addressing worst performing feeders, the SAIDI on such feeders has improved from 17.42 to 5.15 (by 2013). That improvement is notable. The current gap between worst performing and all feeders is 5.15 versus 1.9. Newfoundland Power does not consider this gap sufficient to continue including worst performing feeders in its Distribution Reliability Initiative. Liberty views the remaining gap as substantial enough to warrant the common utility practice of a targeted funding program to address that 10 to 15 percent of feeders exhibiting worst SAIDI and SAIFI performance during the previous year, absent a showing that other expenditures on reliability improvement are more cost effective.

Planning

2.4. Newfoundland Power's Transmission and distribution systems operate effectively in ensuring adequate service reliability.

Planning resources are appropriately organized and staffed. Newfoundland Power employs appropriate criteria and standards. Capacity planning takes an appropriately conservative view of weather conditions. Transmission lines, transmission voltage transformers, and distribution feeders continue to operate overall with healthy margins under current and forecasted load conditions. Distribution substations forecasted to operate in excess of criteria have been slated for capacity increase. Planners conduct an appropriate range of load flow, voltage, short circuit, and protective device coordination studies, supported by sufficient computer-based tools and models. They verify model accuracy through comparisons with actual conditions.

2.5. The expanded work of the Inter-Utility System Planning and Reliability Committee commenced in 2014 should improve planning coordination between Newfoundland Power and Hydro.

2.6. Capital programs have been effective in improving reliability, but better methods for prioritizing projects under consideration exist. *(Recommendation # 2.3)*

Reliability, the largest contributor, drives about half of transmission and distribution capital budgets. Planners sufficiently focus on reliability issues in forming budgets.

Decisions on which projects to fund consider operating benefits, the costs of alternative solutions, and priorities. Newfoundland Power does not, however, employ a structured objective scoring process for prioritizing projects, relying instead on more subjective consideration of engineering judgment, reliability index measures, inspection results, and condition assessments.

Others employ a similar range of factors, but seek to employ them in a more structured, quantifiable, weighted, analytical process. Best practice in doing so also includes the use of a comparison of the expected costs of potential projects in relation to the benefits they may bring in avoided numbers of customer interruptions or minutes of interruptions.

Design

2.7. Newfoundland Power has incorporated appropriate levels of redundancy in its transmission and distribution systems and in its substations.

Newfoundland Power's approach to design incorporates levels of reliability consistent with the nature of its serving areas. Liberty found its levels of redundancy and its availability of emergency generation very competitive with other utilities having a substantial degree of low-density, rural load. Newfoundland Power has looped a sufficient portion (roughly half) of its transmission system, which avoids outages when one line fails. Diesel, gas turbine, or hydro backup generators are available to serve some or all loads to avoid outages during maintenance on radial lines. Only about a quarter of the transmission system has neither transmission looping nor backup generation capability. Moreover, wherever practicable on distribution feeders (249 of Newfoundland Power's total of 306) allow load transfer from one feeder to another feeder. Line ties are not practical for the remaining fifty-seven feeders located in rural areas where no adjacent feeders are available.

2.8. Newfoundland Power employs appropriate design standards, criteria, and practices for transmission and distribution lines.

Overhead transmission and distribution line design exceeds Canadian Standards Association clearance and ice loading standards. When rebuilding lines on the Avalon and Bonavista Peninsulas, the Company uses conservative wind and radial ice criteria. Appropriate measures have been taken to address transmission line galloping in high winds. The Company uses appropriate operating standards to avoid equipment damage and excessive sag. Criteria that permit substation transformers to operate in excess of manufacturer ratings are consistent with industry practices.

2.9. Current use of SCADA and use of automatic reclosers on feeders downstream from substations currently do not serve to minimize interruption frequency and duration. *(Recommendation #2.4)*

Use of SCADA control is appropriate for its transmission system. It directly controls and monitors 94 of its 103 transmission lines and indirectly controls others. SCADA control, however, exists for only about 60 percent of distribution feeders. The Company will begin SCADA replacement in 2015, under plans to include all distribution feeders in its new system. Executing these plans will bring Newfoundland Power into conformity with good utility practices.

Downstream reclosers can reduce by about one-half the number of customers affected by feeder faults occurring past the downstream recloser. Newfoundland Power currently makes only minimal use of these devices. It will have installed some more by the end of 2014. Continuing to install more of these reclosers over time, beginning with those worst and mediocre performing feeders that have substantial loads would be consistent with good utility practices, and presents a likely more cost effective way of further improving distribution reliability.

2.10. Newfoundland Power employs appropriate lightning and animal protection.

Extending ground wires 800 meters out from substations on 138 kV lines, employing lightning arresters on substation transformers and feeders, and installing lightning arresters on feeder-mounted equipment during rebuilds comprise effective measures. The use of insulated coverings, guards and insulated leads have been effective in preventing animal-caused damage and outages.

2.11. Newfoundland Power makes effective use of short circuit studies.

Short circuit studies have been carried out on an effective time cycle, and employed when system changes occur. Newfoundland Power has used them appropriately to address the prevention of circuit breaker failures resulting when fault currents exceed equipment fault duty ratings.

2.12. Completion of in-process developments in the Geographic Information System will increase its effectiveness.

Newfoundland Power only recently, in 2013, implemented a Geographic Information System. The Company recognizes the need to improve the level of accuracy in the system to take it beyond its current sufficiency for use in determining electrical connectivity of the distribution system and locating equipment in the field. It needs to ensure completion of plans for field surveys to gather equipment data and to install in line trucks the capability to update system data in the field.

Protective Relays

2.13. Newfoundland Power's protective relay schemes conform to industry practice, but they do not operate under documented guidance. *(Recommendation #2.5)*

The Company uses reasonable practices and it has for a number of years been replacing obsolete relays with modern programmable relay schemes. It spent more than $10 million to replace relays from 2008 to 2012. Newfoundland Power has not, however, employed a formal protective relay scheme criteria document explaining its protective relaying objectives, approaches, and methods for each electric systems element.

2.14. A temporary delay in testing of electromechanical relays is being addressed.

Reassignment of testing responsibility produced training requirements that caused some delay in testing electromechanical relays. As the end of 2014 approached, Newfoundland Power had nearly completed the testing on its five-year cycle.

2.15. Newfoundland Power does not formally periodically exercise its circuit breakers. *(Recommendation #2.6)*

Newfoundland Power does, however, verify relay to circuit breaker operation when commissioning equipment, investigating operating issues, and when it operates breakers by the SCADA system it does so via programmable relays, where applicable.

2.16. Newfoundland Power does not centrally track actions to address the causes of frequent protective device operations. *(Recommendation #2.7)*

Area operating personnel identify and address multiple protective device operations (such as feeder tap fuses) occurring within a year. Some such operations may not have a material impact on overall SAIFI and SAID metrics, but nevertheless produce dramatic outage effects for a small number of customers. Many utilities, but not Newfoundland Power, formally track "multiple protective device operations" (usually three or more operations of the same device during a rolling 12 months) to ensure that even very small numbers of customers are not experiencing multiple service interruptions. Best practice requires resolving the causes of multiple operations promptly. Personnel in the field may now be addressing multiple device operations effectively, but central tracking comprises a material element in verifying that effectiveness.

E. Recommendations

Reliability

2.1. Increase the emphasis on the Rebuild Distribution Lines initiative in annual capital budgets, with the goal of reducing distribution equipment failures. *(Conclusion #2.2)*

2.2. Perform a structured evaluation of the costs and benefits of reinstituting a regular annual program for addressing worst performing feeders. *(Conclusion #2.3)*

The program employed in the past has produced very substantial reliability improvements. While the gap between worst performing and all feeders is now much narrower, it is not clear that the gap has become small enough to make continuation uneconomical. The Company should assess in a structured, analytical way the cost/benefit ratio for this program, in comparison with other programs that its resumption might displace.

Planning

2.3. Develop a weighted analytical scoring of criteria process to support capital planning; include in this a scoring criterion that relates expected project costs to avoided numbers of customer interruptions or minutes. *(Conclusion #2.6)*

Using a process for scoring project selection criteria is good utility practice. Newfoundland Power should also consider including cost versus anticipated avoided customer interruption (CI) and/or avoided customer minutes of interruption (CMI) as part of the scoring process. Using a weighted scoring process would also help justify proposed capital projects to stakeholders, including the Board, and will demonstrate whether a proposed project is needed to primarily improve equipment condition or to primarily improve future reliability (such as improving SCADA). This approach also works to eliminate any subjective bias to the prioritization process.

Design

2.4. Investigate the installation of downstream feeder reclosers for the purpose of improving distribution SAIFI and SAIDI indices, in addition for reducing cold load

pick up difficulties, with priorities given to feeders based on installation costs versus anticipated avoided customer interruptions. *(Conclusion #2.9)*

Protective Relays

2.5. Document protective relay scheme objectives, criteria, and methods for protecting transmission lines, buses, and distribution feeders. *(Conclusion #2.13)*

2.6. Conduct circuit breaker operation tests from relays (so called trip checking) on a periodic basis to assure that all relay trip circuits and circuit breakers operate as intended. *(Conclusion #2.15)*

2.7. Centrally report multiple device operations. *(Conclusion #2.16)*

Newfoundland Power should install a method for ensuring that regional personnel promptly address such operations. The goal is to ensure timely resolution of issues that may produce dramatic effects on customer groups too small to have a material bearing on overall reliability metrics.

III. Asset Management

A. Background

Effective utility asset management seeks to prevent equipment-caused customer interruptions by using cost-effective inspection, maintenance, and rehabilitation practices. Programs and practices should be designed and funded to provide sufficient skilled resources and equipment to accomplish the goals of asset management strategies. Liberty reviewed Newfoundland Power's transmission and distribution asset management strategies, including equipment inspection, repair, replacement, upgrading, maintenance and rehabilitation policies, programs and actual practices, and the adequacy of and its compliance with its strategies. The examination included the practices for maintaining and enhancing the condition and reliability of transmission lines, substation equipment, and distribution feeder poles and other line equipment, and the adequacy of vegetation management practices. Liberty also examined asset management operational organizations, work completion accountability, staffing levels, training, and succession planning and the maintenance management tracking methods used to accomplish its asset management strategy. Chapter V addresses how Newfoundland Power manages and maintains generating facilities, and Chapter II addresses how it manages and maintains its protective relays.

B. Chapter Summary

One of Newfoundland Power's asset management objectives is to detect and correct equipment condition issues before equipment failure occurs. Newfoundland Power performs effectively in minimizing equipment-caused outages. It supplements regular equipment maintenance practices on aged equipment with annual targeted capital equipment rebuild and modernization projects. This approach has contributed to improved reliability metrics since 1999, as described in Chapter II.

Newfoundland Power's asset management team operates under an effective structure with appropriate staffing for planning, scheduling, and tracking asset planning work. It has appropriate numbers of skilled resources, good apprenticeship programs, and conducts succession planning for retiring skilled workers. Vegetation management meets good utility practice. Maintenance work conforms reasonably well to schedules. Inspection and maintenance practices generally conform to good utility practices, however the Company should review its distribution system wood pole inspections practices.

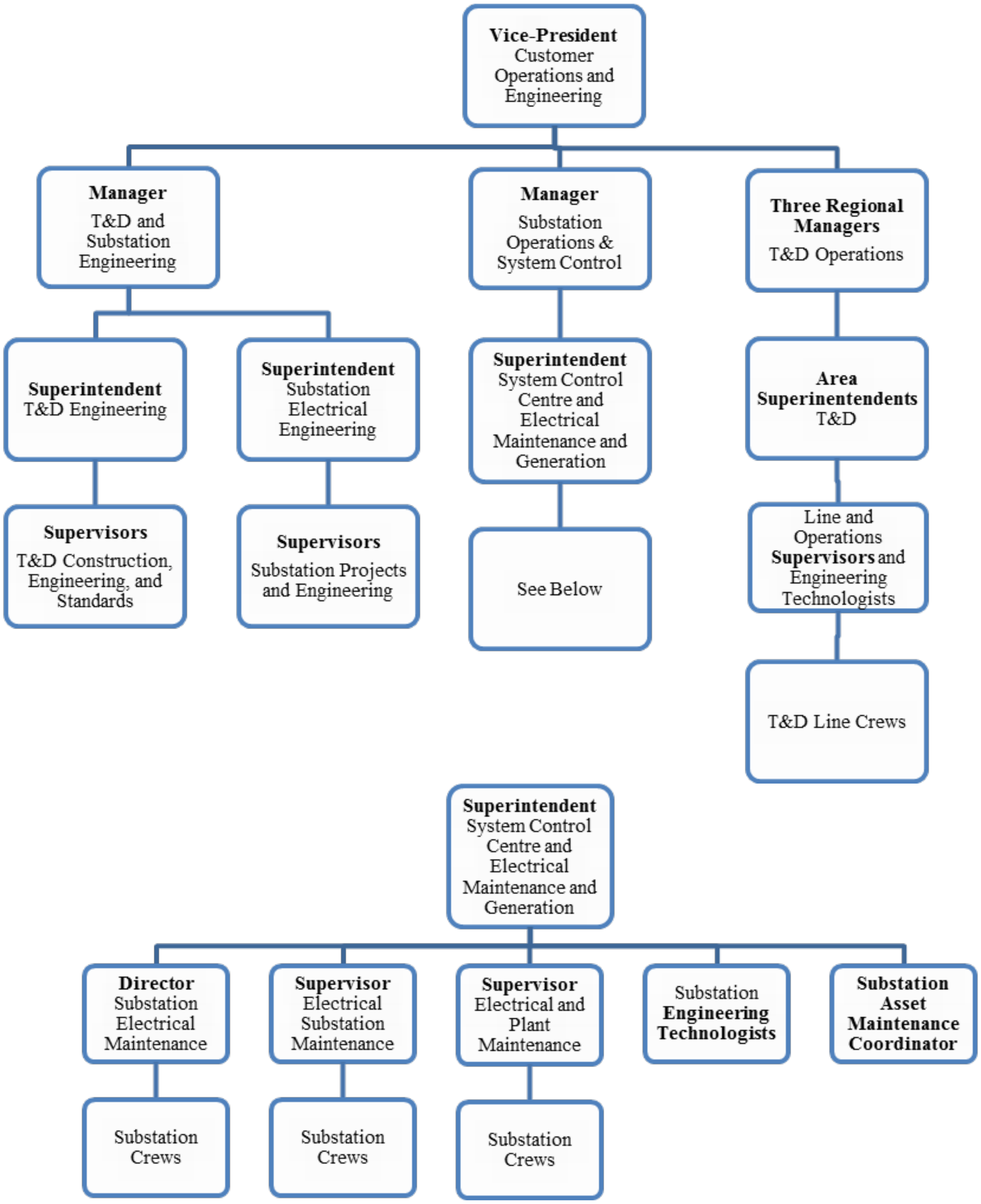
C. Findings

1. The Transmission & Distribution Asset Management Organization

Newfoundland Power's[47] Vice-President of Customer Operations and Engineering has responsibility for overall management of transmission, distribution, and substation electric systems. The Manager of Engineering, the Manager of Operations, and the three Regional Managers (Western Region, Eastern Region, and St. John's Region) all report to the Vice-President. The next table shows the organization.

[47] Responses to RFIs #PUB-NP-135 and 191.

Chart 3.1: Newfoundland Power Asset Management Organization



The Manager of Engineering (T&D and Substation Engineering), referred to in this report as the Manager of Engineering is responsible for policies, standards, practices, and planning for medium- to long-term substation, transmission, and distribution asset management and load growth related initiatives. Superintendents and supervisors carry out medium- and long-term projects.

The Manager of Operations (Substation, Operations & System Control) referred to in this report as the Manager of Operations is responsible for the inspection and maintenance of all substations, including monthly inspections, routine maintenance work, and high priority repairs which cannot be included in larger planned substation projects.

The Superintendent of the System Control Center, Electrical Maintenance, and Generation is accountable to the Manager of Operations for the scheduling and completion of substation inspection and maintenance activities, using the electrical maintenance team. The Manager of Operations and the Manager of Engineering work together to assure that Substation Refurbishment and Modernization Projects and load growth and routine maintenance projects are clustered together to minimize substation outages.

The three Regional Managers (Transmission and Distribution Operations) are responsible for the operations and maintenance of the transmission and distribution systems within their respective regions. The St. John's Regional Manager position was implemented in January 2011 to better address the increasing residential and commercial load growth on the northeast area of the Avalon Peninsula.

The Manager of Operations, the appropriate Regional Manager, and the Vice President of Customer Operations and Engineering are all notified of planned substation and transmission outages. The President/CEO is notified when transmission line or substation outages might be of long duration.

The Superintendents of Operations (one of three in Western Region and one of two each in the Eastern Region and in the St. John's Region) review, assess, and if necessary, prioritize distribution and transmission lines inspections and maintenance jobs on a monthly basis, and routinely report work status to the Regional Managers.

2. Skilled Worker Staffing

Many of the 329[48] full time employees have duties that concern multiple parts of the electrical system. All 153 Power Line Technicians (PLTs) receive training and experience on transmission line, distribution line, and substation construction and maintenance work. Only tenured Technicians with specialized experience qualify for assignment to energized high-voltage circuits on transmission lines and in substations using hot-line methods.[49]

Newfoundland Power's[50] Engineering Technologists also typically work on multiple parts of the system. They provide support in developing and maintaining design, material, and construction standards, provide supervision to construction crews and contractors, implement programs and procedures for the development and operation of power systems, prepare engineering reports to identify, evaluate and make recommendations for system upgrades to the power system, and undertake feeder monitoring and modeling associated with delivery of power and electrical

[48] Response to RFI #PUB-NP-081.
[49] Response to RFI #PUB-NP-193.
[50] Response to RFI #PUB-NP-194.

system loading. Engineering Technologists also interact with developers and contractors, obtain approvals from regulatory bodies, and prepare estimates and material lists.

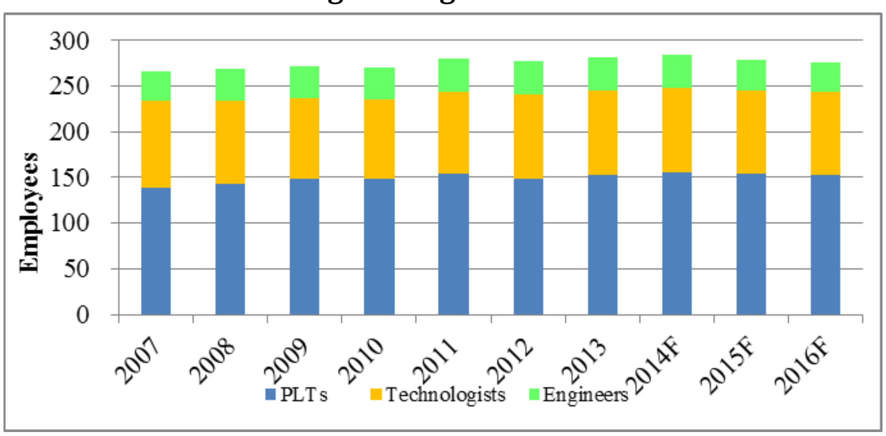
Newfoundland Power's Industrial Electricians work with substation and generation electrical components. They have responsibility for the installation, assessment, and maintenance of electrical equipment.

Newfoundland Power's Industrial Millwrights normally work with generation assets. They perform installation, inspection, and maintenance of generation mechanical equipment. Millwrights also operate generating units and maintain dams and waterways.

The primary functions of Newfoundland Power's[51] Transmission and Distribution Planners include inspection, work planning, and contractor supervision. Work Planners perform transmission line, distribution line, pad mount transformer, and vegetation inspections. Planners also review completed work orders for follow-up and close-out. Planners also work with supervisors to ensure priority work is communicated and completed in a timely manner. Planners implement vegetation management programs including reviewing customer requests for vegetation removal, determining tree trimming and brush clearing requirements during inspections, planning work orders and supervising vegetation contractors.

The next chart and table break down engineering and skilled workers by overall category.

Chart 3.2: Engineering and Skilled Workers



[51] Responses to RFIs #PUB-NP-196 and 197.

Table 3.3: Skilled Workers by Occupation

	2009	2010	2011	2012	2013
Power Line Technicians	148	148	154	149	153
Technologists	88	87	88	91	92
Industrial Electricians	25	27	25	26	25
Industrial Millwrights	14	14	14	14	13
Engineers	36	35	37	37	36
"Work" Planners	15	15	14	11	10
Totals	326	326	332	328	329

The number of Power Line Technicians and Technologists increased, beginning in 2009. The number of Planners (typically Power Line Technicians by training) decreased as the deployment of mobile computing in line trucks, a computerized operations dispatch system, and expanded use of geographic information systems have increased efficiency in planning functions. These changes have made line crew dispatch by the Central Dispatch Team often more effective than using General Forepersons. The latter are also typically Power Line Technicians or Technologists, by training.

Newfoundland Power[52] primarily uses its own Power Line Technicians and Apprentices for new distribution construction, but supplements its workforce with power line contractors. It uses only power line contractors for new transmission line construction. It uses a mix of its own workforce and contractors for its substation refurbishment and modernization capital projects.

3. Newfoundland Power Relay and Control Engineers and Technicians

Newfoundland Power's Protection and Control resources include 8 relay engineers and 6 engineering technologists[53]. Electrical maintenance personnel or electrical contractors install protective relays and control circuit wiring. Newfoundland Power's Protection and Control engineers and engineering technologists are responsible for its protective relay and control designs. Newfoundland Power's engineering technologists (working as relay technicians) are responsible for ensuring that electronic relay and control schemes operate properly. In 2009, the Company began using Electrical Maintenance persons to perform maintenance tests on the older electromechanical relays. Newfoundland Power's power line technicians sometimes record and reset relay targets.

4. Inspection and Maintenance Work Completion Performance

Newfoundland Power[54] targets completion of all required inspections and maintenance work in the year scheduled.[55] Responsibility for distribution, transmission and substation inspections, corrective maintenance and preventative maintenance rests with the Superintendent of Operations and the Superintendent, System Control and Electrical Maintenance. Newfoundland

[52] Response to RFI #PUB-NP-198.
[53] Responses to RFIs #PUB-NP-082, 199, and 201.
[54] Response to RFI #PUB-NP-202.
[55] Response to RFI #PUB-NP-141.

Power holds its Regional Managers and its Manager of Operations accountable for ensuring the timely completion of transmission, distribution and substation inspections and maintenance.

a. Transmission Line Inspections

The next table[56] shows the numbers of transmission inspections scheduled and completed since 2011.

Table 3.4: Transmission Line Inspections

Item	2011	2012	2013
Scheduled	103	103	103
Completed	103	95	96
Number Backlogged	0	8	7
Percent Backlogged	0	8	7

Newfoundland Power indicated that four retirements in 2012 and 2013 caused a need for training new resources, which in turn adversely affected productivity. Tropical Storm Leslie also adversely affected inspection work. When it becomes apparent that some transmission line ground inspections cannot be completed in a year, the Company uses prioritization designations to ensure critical work completion, or may employ aerial (helicopter) to expand coverage. For example, recently rebuilt and looped (providing redundancy) lines typically impose lower outage risk and therefore get lower priority. Completing a current year's program early in the following year presents a last option.

Newfoundland Power reported that all transmission lines not given a full ground inspection in 2012 and 2013 received partial or complete helicopter inspection during the year, underwent ground inspection early in the succeeding year, or presented relatively low risk of customer impact.

b. Transmission Line Repair/Replacement Performance

The next table shows recent year[57] transmission lines corrective work performed and backlogged.

Table 3.5: Transmission Repairs and Replacements

Item	2011	2012	2013
Total	127	353	144
Completed	91	309	139
Number Backlogged	36	44	5
Percent Backlogged	28	13	4

Repairs can encompass small items (*e.g.*, cross arm, insulator string) or a complete structure. Management monitors backlogged repairs to assure that the backlogged do not affect reliability. The higher number of repair items in 2012 resulted in major part from a large transmission line

[56] Response to RFI # PUB-NP-062 (1st Revision).
[57] Response to RFI #PUB-NP-062.

rehabilitation project that involved the correction of 184 deficiencies. Newfoundland Power[58] reported that the backlogged work shown in the tables represented lower priority tasks completed subsequently. The next table summarizes completion data for backlogged items.

Table 3.6: Backlogged Transmission Order Completions

Year	Backlog	Completed	
		Following Year	Later
2011	36	19	17
2012	44	40	4
2013	5	5	0

c. Transmission and Distribution Pole Replacements

The next table shows recent transmission and distribution pole replacement numbers.[59]

Table 3.7: Wood Pole Replacements

Type	Number	2009	2010	2011	2012	2013
Transmission	24,283	219	441	578	320	261
NP-Owned Distribution	210, 002	1,268	1,620	730	976	869
Joint-Owned Distribution	84,720	0	0	487	471	428
Total Distribution	294,722	1,268	1,620	1,217	1,447	1,297

Newfoundland Power replaced about 7.5 percent of its transmission poles and about 2.3 percent of its distribution poles from 2009 through 2013 under its maintenance programs and its transmission line and distribution feeder rebuild strategies. On average the Company has been replacing transmission poles at about 1.5 percent per year, and distribution poles at about 0.5 percent per year. At these replacement rates, Newfoundland Power is replacing its transmission poles every 67 years and its distribution poles about every 200 years. Newfoundland Power replaces poles under its Rebuild Distribution Lines initiative.

d. Distribution Line Inspections

The next table shows[60] distribution line inspection work in recent years. Backlogs have been nominal.

[58] Response to RFI #PUB-NP-204.
[59] Responses to RFIs #PUB-NP-063 and 070.
[60] Responses to RFIs #PUB-NP-069 (1st Revision) and 208.

Table 3.8: Distribution Feeder Inspections

Inspections	2011	2012	2013
Total	46	44	47
Completed	45	43	44
Number Backlogged	1	1	3
Percent Backlogged	2	2	6

e. Pad Mount Transformer Inspections

The next table shows[61] pad mount transformer inspection work performed in recent years. Backlogs here have also been nominal.

Table 3.9: Pad Mount Transformer Inspections

Inspections	2011	2012	2013
Total	1,228	1,215	1,246
Completed	1,220	1,193	1,216
Number Backlogged	8	22	30
Percent Backlogged	<1	2	2

f. Distribution Repair Work

The next table shows[62] the numbers of distribution line repair jobs conducted and backlogged in recent years. Backlogs have been much more substantial here.

Table 3.10: Distribution Repair Work

Jobs	2011	2012	2013
Total	845	1,143	1,021
Completed	554	824	753
Number Backlogged	292	321	267
Percent Backlogged	35	28	26

Newfoundland Power[63] prioritizes distribution corrective maintenance jobs, in order to address first those equipment issues most likely to cause an outage. It regularly reviews the status of backlogged work orders. The Company sometimes schedules them in clusters as part of capital projects, depending on priority, outage scheduling, and similar work. The next table shows progress in completing backlogged items in years following initial order creation. To illustrate, the Company completed 65.5 percent of 2011 orders in 2011, had completed 83.2 percent of them by the end of 2012, and has completed 99.6 percent of them as of mid-August 2014.

[61] Responses to RFIs #PUB-NP-069 and 067.
[62] Response to RFI #PUB-NP-069 (1st Revision).
[63] Response to RFI #PUB-NP-209.

Table 3.11: Cumulative Distribution Work Orders Completed

Created	2011	2012	2013	2014
2011	65.5%	83.2%	94.6%	99.6%
2012		72.0%	94.1%	99.4%
2013			73.8%	97.3%

g. Substation and Protective Relay Inspections and Maintenance

Newfoundland Power[64] employs the following annual preventive maintenance completion targets:

- Substation inspections: 11 per year, only once during July/August, 100 percent completion target
- Oil sampling from power transformers, tap changers, and bulk oil circuit breakers: annual, more frequently if necessary, 100 percent completion target
- Vibration analyses on transformer load tap changers: annual, 100 percent completion target
- Battery bank tests: every six months, 100 percent completion target
- Substation thermographic inspections: annual, 100 percent completion target
- Portable substations maintenance: annual, 100 percent completion target
- Substation transformer maintenance: 12-year cycle, less if condition indicates the need for maintenance, target of 8 percent of transformers each year
- Relay Maintenance: 5-year cycles, 100 percent completion target
- Circuit breaker maintenance: 10-year cycle, less if condition indicates the need for maintenance, target of 10 percent of breakers each year.

The next table summarizes substation equipment maintenance numbers targeted and the percentages of those numbers completed in recent years.[65]

Table 3.12: Substation MaintenanceTarget Numbers and % Completed

Year	2011	2012	2013	Average Completion
Preventive Maintenance	**Number (%)**	**Number (%)**	**Number (%)**	**%**
Substation Inspections	1,624 (95)	1,625 (89)	1,290 (96)	93
Equipment Oil Samples	452 (97)	474 (98)	459 (98)	98
Tap 4 Vibration Analysis	- (-)	66 (86)	70 (93)	90
Battery Maintenance	396 (97)	382 (85)	427 (83)	88
Thermography Inspections	131 (98)	131 (99)	187 (98)	98
Portable Substation Maintenance	3 (100)	3 (100)	3 (100)	100
Power Transformer Maintenance	16 (50)	16 (63)	16 (106)	73
Breaker/Recloser Maintenance or Replace	36 (69	36 (94)	36 (89)	84
Relay Maintenance`	176 (63)	128 (45)	120 (106)	70

The Company reported that reduced transformer work completion in 2011 and 2012 and reduced circuit breaker completions in 2011 resulted from reduced resources caused by a 2010 ice storm

[64] Responses to RFIs #PUB-NP-066, 210, and 233.
[65] Response to RFI #PUB-NP-212.

and hurricane, among other things. The Company experienced Tropical Storm Leslie in 2012. This storm required resource redirection, which affected completion of lower priority jobs. Substation investment also increased materially from 2011 through 2013. The approximately $13 million per year exceeds by 60 percent the approximately $8 million spent per year from 2008 through 2010. This increase also stressed resource availability for other work.

Newfoundland Power's[66] completion rate for relay maintenance testing and calibration in 2013 was 106 percent, in contrast to the 2011 through 2013 rate of 70 percent. The Company changed its relay maintenance program in 2009. It began using electrical maintenance personnel rather its electrical engineering technologists for testing electro-mechanical relays. The large backlog of relay maintenance in 2011 and 2012 was largely due to Tropical Storm Leslie and to training and test set availability issues, which have been resolved. As of August 15, 2014, out of the 762 electromechanical relays scheduled for maintenance since 2009, only 42 relays were backlogged, with the remainder scheduled for completion within the current 5-year maintenance cycle.

5. T&D Inspection and Maintenance Monitoring

Power[67] schedules and tracks transmission line inspections and resulting maintenance activities via its computerized Transmission Asset Management System (TAMS) software application. The Company schedules and tracks seven-year distribution line inspections and its three and a half-year Vegetation Management inspections and maintenance activities via its computerized Avantis maintenance tracking software application. Transmission line and distribution feeder inspectors use handheld devices to record inspection data and typically download the results of their inspections daily into the applicable program. Regional Planers prioritize discovered deficiencies, in consultation with Supervisors who schedule the corrective maintenance items. Supervisors, Superintendents, and Regional Managers access the systems to monitor the performance of inspections and required actions.

The highest priority repairs (emergency) are scheduled for completion within a month via the Outage Management System (OMS). The System Control Center, working with regional personnel, control the corrective maintenance work. Corrective maintenance jobs having lower priorities are clustered, based on priorities, with other work and completed under the following year's *Transmission Line Rebuild Projects* or *Rebuild Distribution Lines Projects*. Regional supervision manages this work.

Superintendents of Operation monitor inspections and corrective maintenance monthly. They reprioritize activities as necessary.[68]

Newfoundland Power's[69] Vice-President of Customer Operations and Engineering reviews the performance of the Company's maintenance activities with Regional Managers on a regular basis. This review includes a status update for maintenance activities, along with to-date progress

[66] Response to RFI #PUB-NP-211.
[67] Responses to RFIs #PUB-NP-060, 067, and 213.
[68] Response to RFI #PUB-NP-136.
[69] Response to RFI #PUB-NP-214.

on the capital maintenance program. Typically quarterly, this review sometimes occurs more frequently, as circumstances dictate.

In 2013, Newfoundland Power installed a computerized operations dispatch system[70]. It expanded the use of its graphic information systems for its vehicles and for its electrical system assets to improve inspection and maintenance work performances, improve responses to outages, and improve the efficiencies of managing field operations including inspections, maintenance, and capital projects.

6. Substation Inspection and Maintenance Monitoring Methods

Newfoundland Power[71] also uses its Avantis maintenance management system database for managing substation equipment and maintenance data. Each regionally based substation Asset Maintenance Coordinator has responsibility for compliance with activities required by the Substation Maintenance Standards Manual. The Company also uses its maintenance software program to schedule and to track routine substation preventive maintenance work, monthly substation inspections, and resulting corrective maintenance. The Asset Maintenance Coordinator, monitors substation inspections, corrective maintenance jobs, and routine maintenance status. The coordinator conducts weekly scheduling meetings with regional substation maintenance supervisors and superintendents to discuss and adjust job scheduling and status.[72]

7. Transmission and Distribution Line Programs

a. Transmission Line and Feeder Inspection and Maintenance Practices

Regional Managers ensure that transmission and distribution line inspection and maintenance activities are completed in accordance with Newfoundland Power's policy. Responsibility for maintaining and revising this policy rests with the Superintendent, responsible for Transmission. Newfoundland Power conducts transmission line and distribution feeder equipment and ground (walking and using ATVs) inspections, and it repairs deficiencies identified by the inspections. The Company conducts transmission line and vegetation inspections at least on an annual basis. It conducts distribution feeder and feeder equipment inspections at least on seven-year cycles. Newfoundland Power[73] conducts annual infrared inspections of all major distribution equipment, including voltage regulators, reclosers, sectionalizers, capacitors, and associated switches. It also conducts infrared inspection on primary connects and cutouts on mainline feeders once every seven years with the regular distribution feeder inspections.

Newfoundland Power conducts at least one detailed ground inspection for each transmission line on an annual basis and at least one inspection in a four year period is conducted when snow is not covering the ground. Additional unscheduled ground inspections, and sometimes specific

[70] Response to RFI #PUB-NP-278.
[71] Response to RFI #PUB-NP-064.
[72] Response to RFI #PUB-NP-136.
[73] Response to RFI #PUB-NP-230.

detailed climbing inspections and helicopter inspections are conducted to investigate storm damage or operating issues.

Newfoundland Power[74] conducts at least one detailed inspection from the ground on each distribution feeder on at least a seven-year cycle. Special inspections are conducted to investigate specific feeder condition and performance issues. The seven-year inspections include feeder-mounted capacitor banks. Feeder-mounted automatic reclosers and voltage regulators are inspected quarterly under the substation inspection program.

Newfoundland Power's line inspectors (Regional Planners) identify poor transmission and distribution pole and tower conditions, and inspect all conductors, cross arms and braces, insulators, switches, anchors, dead ends, jumpers, sleeves, capacitor banks, guy wires, and other hardware and devices. They inspect the transmission rights of ways for encroachments, vegetation, and other unacceptable conditions. The inspectors enter all deficiencies, and deficiency priority levels, and each pole's or tower's GPS coordinates (transmission lines only)[75] into digital inspection forms on the handheld recording devices. The inspectors also take digital photographs of deficiencies, if necessary. Newfoundland Power does not use handheld computers for recording distribution inspections.

T&D line inspectors[76] verify the condition of all wood poles by examining each from top to ground line for pole top rot, ground line rot, external decay, deterioration, splits, checks, cracks, breaks, fire damage, woodpecker damage, insect infestation, and out of plumb condition. Inspectors conduct "sounding" tests on transmission poles over 35 years old to identify internal voids, caused by decay or insects, for example. The inspectors randomly sound transmission poles less than 35 years old and any that appear to be decayed. Newfoundland Power does not apply fungal or insect treatment to poles because it feels that the cool Newfoundland weather precludes the need to do so. Inspectors sound distribution poles only when a pole appears to be decayed.

The inspectors correct minor transmission or distribution deficiencies while on site as part of routine operating maintenance work. The inspectors prioritize deficiencies based on the Company's General Guidelines for Classification of Priority[77] for transmission line inspections and on the Company's Deficiency Tables[78] for distribution feeder inspections. Work Planners assign repair priorities to the non-emergency deficiencies, and report high priority deficiencies to supervisors and to the Central Dispatch Team for scheduling in the Outage Management System.[79] TD1 (serious) priority deficiencies are corrected within seven days. TD2 (less serious) priority deficiencies are corrected within one month. TD 3 (minor hazard) priority deficiencies are corrected within six months. TD 4 (no safety hazard) priority deficiencies are corrected during following years under capital budgets.

[74] Response to RFI #PUB-NP-219.
[75] Response to RFI #PUB-NP-221.
[76] Responses to RFIs #PUB-NP-060 and 223.
[77] Response to RFI #PUB-NP-060.
[78] Response to RFI #PUB-NP-067.
[79] Response to RFI #PUB-NP-215.

Planners are responsible for organizing the resources necessary to timely complete priority TD1 and priority TD2 repairs. Priority TD3 repairs are included in monthly maintenance schedules, as appropriate. Regional Superintendents and/or Supervisors are ultimately accountable for completion of repairs within time frames. Corrective maintenance jobs more than six months overdue are reported to the *Regional Managers* for action.

High priority capital work that cannot wait until the next budget year is completed under the Reconstruction capital project. For example, deteriorated or damaged distribution structures and electrical equipment deemed to present a risk to safety or reliability are addressed through the Reconstruction project within the year identified.

Newfoundland Power[80] has 96 underground residential distribution (URD) cable loops, which employ more than 700 cable sections. When a cable fault occurs, an outage ticket is created in the Outage Management System and a line crew is immediately dispatched to isolate the fault and restore service. Following service restoration, the line crew routes the outage ticket to the appropriate supervisor for follow-up replacement of the faulted section. Rather than repairing old deteriorated cables, Newfoundland Power installs new ones, located in conduits.[81]

Newfoundland Power indicated that it normally restores its URD loops immediately and most loops are restored within two weeks. As of August 21, 2014, no URD cables are out of service due to failure.

b. Transmission and Distribution Line Expenditures

The next tables summarize[82] capital and O&M expenditures for transmission line and distribution line inspections, corrective maintenance and preventive maintenance work.

Table 3.13: Transmission Line Maintenance Costs ($ thousands)

Category	2010	2011	2012	2013
Inspections	212	211	197	163
Corrective Maintenance	246	259	150	69
Preventive Maintenance	2,110	1,186	2,071	2,303

Table 3.14: Distribution Line Maintenance Costs ($ thousands)

Category	2010	2011	2012	2013
Inspections	174	191	246	285
Corrective Maintenance	2,419	1,000	654	859
Preventive Maintenance	1,613	3,504	3,981	3,664

[80] Responses to RFIs #PUB-NP-216 and 217.
[81] Liberty meeting with Newfoundland Power on September 19, 2014.
[82] Responses to RFIs #PUB-NP-224 and 225.

c. *Vegetation Management*

Newfoundland Power[83] inspects transmission lines for vegetation (trees, limbs, and brush) clearance issues on annual cycles and it inspects its distribution lines for vegetation clearance issues on 3.5 year cycles. It inspects each transmission line annually and inspects each distribution feeder for vegetation issues twice every seven years; once every seven years as part of walking distribution feeder inspections and, in between, by drive-by inspections. Newfoundland Power also reinspects lines after the inspection year when the actual tree trimming and other vegetation management work is conducted. Line inspectors record the vegetation management data in handheld devices which they upload into the Company's tracking programs. Newfoundland Power reports that less than three percent of power interruptions are attributable to tree contact. It believes that reducing tree-caused customer interruptions during normal conditions by even another fifty percent, would produce only a one percent improvement in overall reliability.

Based on the results of each year's inspections, Newfoundland Power solicits contractor proposals to perform brush cutting, tree trimming, and tree removal work for the following year, specifying that work follow its detailed specifications. The next table lists the width to which contractors must trim limbs from ground to sky.

Table 3.15: Vegetation Clearance Distances

Line Type	ROW Width
138 kV H-frame	26 meters
66 kV H-frame	20 meters
66 kV single pole	15 meters
Three-phase distribution	7.4 meters
Two-phase distribution	7.4 meters
Single-phase distribution	5.4 meters
Secondary distribution	5.4 meters
Communications	1.0 meter

Newfoundland Power's contractor also cuts brush from right of ways, and removes "Danger Trees" outside of right of ways which could fall into the power lines, including dead, mostly dead, and diseased trees, unsound and leaning live trees, and shallow rooted trees. Newfoundland Power's full time arborist works with vegetation management personnel.[84] Newfoundland Power's[85] operating expenditures for vegetation management (shown in the next table) have increased from $997,000 in 2003, primarily because of the effects of increasing numbers of tropical storms and hurricanes.[86]

[83] Responses to RFIs #PUB-NP-067, 080, 222, 226, and 228.
[84] Liberty meeting with Newfoundland Power on June 19, 2014.
[85] Responses to RFIs #PUB-NP--227 and 309.
[86] Response to RFI #PUB-NP-227.

Table 3.16: Vegetation Management Expenses

Year	Capital	O&M
2010	$1,002,512	$1,671,780
2011	$536,269	$1,611,501
2012	$796,571	$1,745,661
2013	$819,646	$1,993,000

d. Substation Inspection and Corrective Maintenance Practices

Newfoundland Power's[87] substation technicians (Industrial Electricians) conduct substation inspections on a near monthly basis, including four quarterly *long inspections* each year and seven (only one in July/August period) *short monthly inspections* between the long inspections each year. Newfoundland Power also conducts infrared inspections of substation equipment during the first quarter of each year.[88] The Company may sometimes postpone short inspections if the technicians are needed for more important maintenance activities. Long inspections are detailed substation and equipment-specific formal inspections of all equipment in each substation. The inspectors use handheld devices and have the ability to update forms for each substation. The Company implemented the use of handheld devices in 2007.[89] Short inspections are walk-around inspections intended to identify more obvious equipment safety and operating issues.

Inspectors report emergency repairs when a substation deficiency is hazardous or might cause an outage. They classify these repairs as Emergency (address immediately) or Urgent (repair within one week). The inspector prioritizes other deficiencies whether as P1 (repair within one month) or P2 (repair within three month). Minor deficiencies are clustered with other work and included in capitalized substation projects.

Newfoundland Power does not segregate substation operating costs by inspections, preventative maintenance and corrective maintenance, but provided its total annual substation operating and maintenance costs. The next table shows total expenses for recent years.

Table 3.17: Substation Operating Costs ($ thousands)

	2010	2011	2012	2013
Total	2,340	2,242	2,555	2,672

The next table shows capital expenditures for substation work.

[87] Responses to RFIs #PUB-NP-064, 065, 066, and 143.
[88] Response to RFI #PUB-NP-230.
[89] Liberty meeting with Newfoundland Power on September 19, 2014.

Table 3.18: Substation Capital Costs ($ thousands)

	2010	2011	2012	2013
Corrective	2,388	2,689	3,267	3,485
Preventive	3,202	3,661	2,279	3,495

e. Substation Preventive Maintenance Practices

Newfoundland Power's[90] substation equipment proactive preventive program and its reactive corrective maintenance program consist of five maintenance categories. The Company's Standard Procedures describe the tasks required for each type of maintenance, which consist of:

- ***Maintenance I:*** Tasks for commissioning new or relocated equipment
- ***Maintenance II***: Tasks required for routine monthly substation inspections
- ***Maintenance III***: Detailed periodic maintenance activities of substation equipment, including diagnostic tests and conducting minor repairs; intrusive maintenance requiring disassembling equipment is conducted based on need, as determined by inspections and test results[91]
- ***Maintenance IV***: Major substation equipment maintenance tasks (overhauls) usually triggered by time (maximum of 10-year cycles),[92] or by deficiencies identified by Maintenance I, III, or V activities (inspections and tests)
- ***Maintenance V***: Unscheduled reactive corrective maintenance (major urgent repairs) tasks carried out following malfunctions or modifications.

Liberty reviewed Newfoundland Power's substation equipment maintenance guideline document, which indicates the tasks to do for each type of maintenance indicated under Type I, II, III, IV, and V Maintenance, and its electronic test sheets. Liberty found that the Company's maintenance guidelines and equipment test sheets were appropriate.

Newfoundland Power[93] uses senior engineers and engineering technologists for investigating substation equipment operating and condition issues and for leading failure investigations. These senior engineers and engineering technologists have specialized knowledge and expertise developed during their long experience working with the Company's electrical equipment, and by regularly taking part in specialized training provided by equipment manufacturers.

8. T&D Critical Spares

Newfoundland Power[94] maintains an inventory of transmission and distribution lines materials in its Central Stores facility in St. John's and in eight area offices located throughout the service territory. It stores spare equipment and parts for substations (such as circuit breakers, voltage regulators, and instrument transformers) at its Mount Pearl Electrical Maintenance Center. An outside supplier provides and installs new wood poles under a consignment contract. Wood pole inventories are maintained at the pole supplier's facility and at the contractor's eight storage

[90] Responses to RFIs #PUB-NP-064 and 065.
[91] Liberty meeting with Newfoundland Power on September 19, 2014.
[92] Responses to RFI #PUB-NP-064.
[93] Response to RFI #PUB-NP-232.
[94] Responses to RFIs #PUB-NP-033 and 235.

yards located throughout the territory. In August 2014, about 3,000 spare poles were available in Newfoundland.

For some equipment, Newfoundland Power also requires, via contractual agreements, some of its electrical system equipment vendors to maintain dedicated release quantities in local warehouses to help ensure adequate equipment and parts are available outside of Newfoundland Power's internal inventory.

Newfoundland Power reported that it regularly reviews its numbers of spare transmission and distribution equipment, parts, and materials and that it has not had any issues having sufficient line materials during past ice storms. The Company maintains an inventory sufficient for rebuilding five kilometers of transmission lines and it can share materials with Hydro.

9. Transmission Rebuild Strategy

In 2005, a detailed evaluation of transmission lines led to the conclusion that lines constructed since the late 1960s and 1970s (built to near modern Canadian Standards Association and current Company standards) could be rebuilt appropriately by applying the Company's normal inspection and maintenance practices. The study also concluded that transmission lines constructed prior to that time were more aged and not necessarily designed to more modern standards. At that time, thirty-nine percent (about 800 km) of the transmission system consisted of lines constructed from the 1940s through the 1960s.

Newfoundland Power developed a 10-year Transmission Line Rebuild Strategy to supplement its transmission inspection and maintenance program. The Company began in 2006 to include the new strategy in annual capital budgets. Newfoundland Power has steadily replaced aged transmission system sections and troublesome components. The Company has updated the strategy to employ line rebuild priorities that reflect updated reliability data, inspection information, condition assessments, and potential failure impact on customers. Newfoundland Power rebuilds line sections to exceed strength standards, in order to better withstand ice and wind conditions. Between 2007 and 2013, the Company rebuilt 17 kilometers of 138 kV transmission lines, 17 kilometers of 66 kV transmission lines, and will have rebuilt another 16 kilometers of 66 kV transmission lines during 2014 for a cost of about $3.17 million. It plans to rebuild sections of another ten transmission lines by the end of 2018, and another eight transmission lines by the end of 2015.

10. Distribution Rebuild Strategy

Newfoundland Power's[95]annual Reconstruction Project and its Rebuild Distribution Lines Project involve the replacement of deteriorated distribution structures and electrical equipment previously identified through the Company's ongoing inspection program, or as a result of engineering reviews. The items typically replaced include poles, cross arms, conductor, cutouts, surge/lightning arrestors, insulators, and transformers. Individual distribution feeder projects are identified through Newfoundland Power's seven-year distribution inspection cycle, which inspects approximately forty-three feeders each year.

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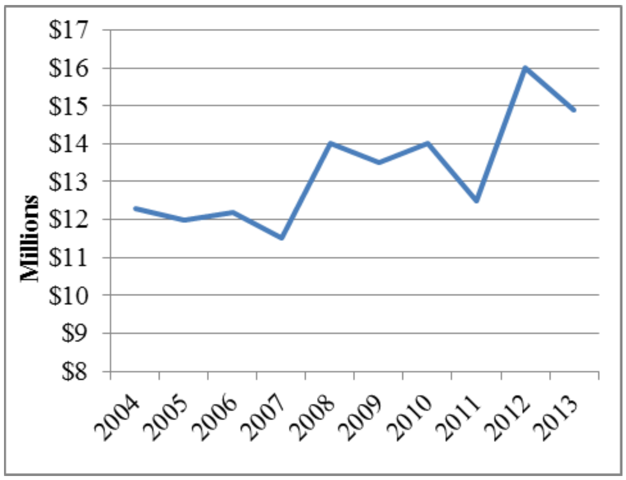
[95] Response to RFI #PUB-NP-270.

Newfoundland Power's[96] Distribution Reliability Initiative project involves the replacement of deteriorated poles, conductor and hardware to reduce the frequency and duration of power interruptions to customers served by specific distribution lines. The Company identifies the fifteen worst performing feeders each year, based on reliability metrics, and carries out engineering reviews of all identified feeders. Where necessary, the Company carries out detailed engineering inspections to determine what reliability-focused work is required.

Newfoundland Power[97] does not track the amounts of distribution feeders rebuilt each year by project type. It reported that in total it rebuilds about fifty kilometers of distribution feeders every year. The next chart shows recent-year capital expenditures for distribution plant replacements

Table 3.19: Distribution Plant Replacement



11. Substation Refurbishment and Modernization Strategy

Nearly one-half of Newfoundland Power's 130 substations were over 40 years old in 2006 and about one-third were over 50 years old. Much of its substation transformers, oil-circuit breakers, structures, and other equipment had been in service since the substations were built. The Company determined that its maintenance practices would not remain sufficient to maintain the very old and obsolete equipment in reliable condition. In 2007, Newfoundland Power determined that capital substation refurbishment and modernization projects were justified for about 80 percent of its substations over the following 10 years. The Company enhanced its substation equipment maintenance programs, which had been in effect at least since 1986, with an annual capitalized Substation Refurbishment and Modernization program. Since 2007, Newfoundland Power has been replacing aged and troublesome components of its substations.

[96] SAIDI is the system average interruption duration index, calculated by dividing aggregate customer hours of outages by the number of customers served. SAIFI is the system average interruption frequency index, calculated by dividing aggregate number of customer interruptions by the number of customers served. CHIKM is the customer hours of interruption per kilometer and is calculated by dividing aggregate customer hours of outages by the kilometers of distribution plant. CIKM is the customers interrupted per kilometer, calculated by dividing aggregate number of customer interruptions by the kilometers of distribution plant. Customer-minutes is calculated by multiplying the number of outage minutes by the number of affected customers.
[97] Response to RFI #PUB-NP-237.

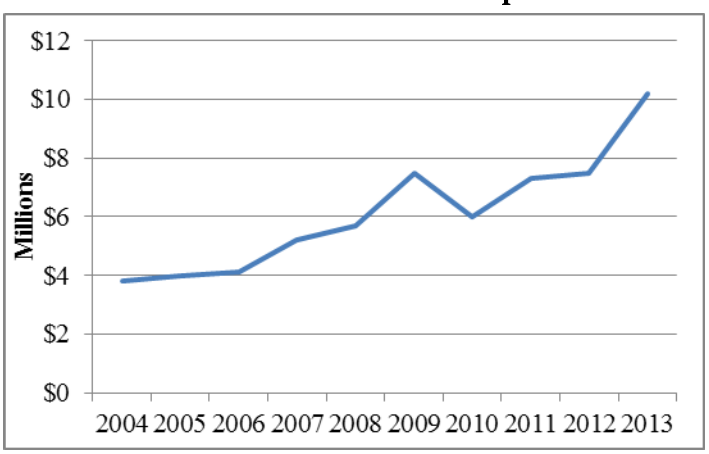
Newfoundland Power's strategy prioritizes for replacement deteriorated and obsolete substation facilities in a stable fashion, under its annual Substation Refurbishment and Modernization program. Newfoundland Power reviews its substation refurbishment and modernization plan annually. When updating the plan, the Company makes assessments based upon the condition of the infrastructure and equipment, the need to upgrade and modernize protection and control systems, and other relevant work. Newfoundland Power has replaced substantial amounts of substation equipment under its asset management programs since 2004. The next table shows substation equipment replaced since 2004.

Table 3.20: Replaced Substation Equipment

Equipment	Replaced	In Service
Circuit Breakers	111	410
Reclosers	56	200
Voltage Regulators	157	360
Power Transformers	9	190
Potential Transformers (PTs)	224	360
Current Transformers (CTs)	44	90
CT/PT Metering Units	51	51

The next chart shows capital expenditures for substation refurbishment and modernization projects.

Chart 3.21: Substation Plant Replacement



Newfoundland Power is upgrading six more substations in 2014 for a cost of about $6 million. It plans to upgrade another twenty substations by the end of 2018.

12. Worst Performing Feeders

As indicated above,[98] distribution reliability improvement strategies include a Worst Performing Feeders Program that addresses feeders, as identified by analysis of performance over the previous rolling five-year period. The next table[99] shows the "worst performing feeders" addressed in Newfoundland Power's Distribution Reliability Initiative capital project since 2004. Newfoundland Power commenced formally addressing its worst performing feeders in 1998. Although Newfoundland Power still identifies its worst performing feeders and corrects some issues, the reliability indices have not been sufficiently high since 2011 to include new worse performing feeders in its Distribution Reliability Initiative.

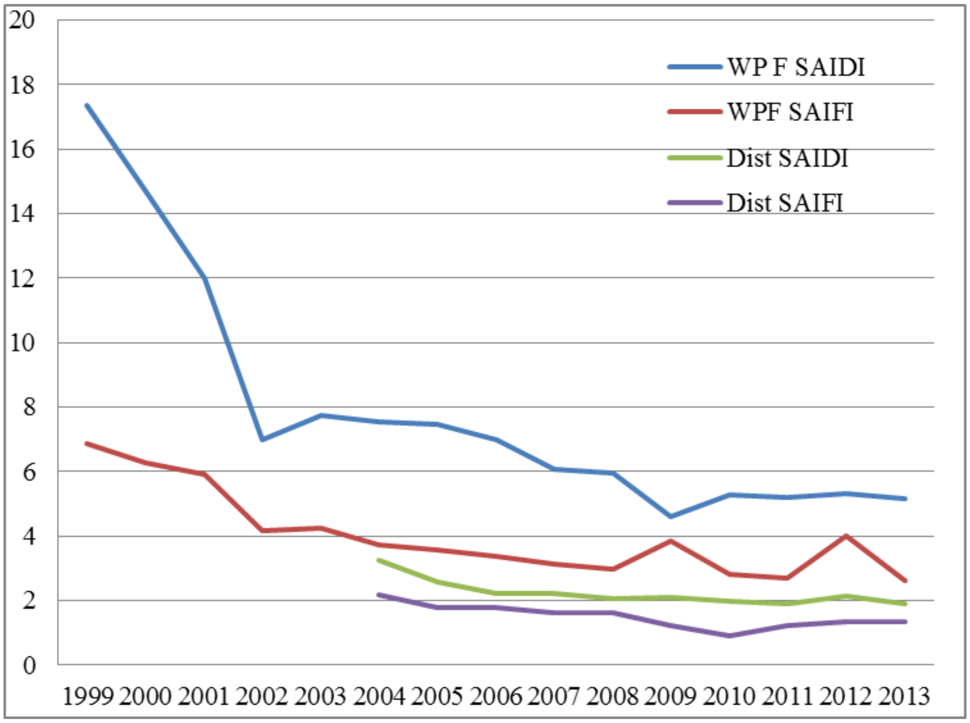
Table 3.22: Worst Performing Feeders Addressed

2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
WES-02	WES-02	BCV-02	None	BOT-01	NWB-02	NWB-02	None	None	None
BRB-04	GBY-02	BOT-01		LEW-02	LEW-02				
PUL-01		LEW-02		GLV-02	GLV-02				
PUL02		GBY-02							
		GPD-01							
		GLV-02							
		SMV-01							

Newfoundland Power has reduced the average SAIDI of its worst performing feeders from about 17.42 to 5.15 in 2013, as the next chart demonstrates.[100] This chart illustrates the improvement of Power's worst performing feeders (WPF) since 1999. However, in 2013, the average SAIDI for Power's Worst Performing Feeders was still 5.15 compared to a SAIDI of 1.9 for the Company's Distribution System.

[98] Response to RFIs #PUB-NP-068 and 285.
[99] Response to RFI #PUB-NP-290.
[100] Response to RFI #PUB-NP-310.

Chart 3.23: Average Worst Performing Feeder SAIDI and SAIFI Compared to Distribution System



D. Conclusions

3.1. Asset management at Newfoundland Power operates: (a) under a program, (b) with an organization, and (c) with the support of sufficient numbers and skills to meet system reliability needs effectively.

Liberty has found at some utilities that the asset management organizations do not have sufficient authority, control, or overview for ensuring that all areas of field operations complies with the corporate asset management organization agendas. Liberty found that Newfoundland Power's organization has appropriate authority, control, and overview to ensure that all asset management work is conducted consistently with sufficiently scoped, designed, and executed objectives, strategies, programs, initiatives, planning, scheduling, monitoring, and measurement.

Newfoundland Power's Manager of Engineering is responsible for policies, standards, practices, and planning for medium to long term substation, transmission, and distribution asset management and load growth related initiatives which require capital expenditures to install new equipment or maintain or replace existing equipment. Newfoundland Power's Vice-President of Customer Operations and Engineering has the ultimate responsibility for the overall management and integrity of the Company's electric systems. The Manager of Engineering, the Manager of Operations, and the three Regional Managers (Western Region, Eastern Region, and St. John's Region) all are accountable to the Vice-President for completing asset management maintenance and project work under their authority. The trail of responsibility appropriately flows down to superintendents, to supervisors, and to crews.

Newfoundland Power's number of skilled workers, engineers and technologists, and contractors appear to be sufficient for the Company to comply with its asset management agenda. The Company monitors the numbers of workers in each category about to retire and bases hiring and training new employees on its succession studies. Newfoundland Power has an intensive apprenticeship program and provides other training as necessary.

3.2. Newfoundland Power uses an effective combination of periodic O&M inspection and maintenance programs and capital transmission, distribution, and annual capital substation capital rebuild and modernization projects to address condition, reliability, and operating issues with its transmission, distribution, and substation assets.

About one-third, more or less, of Newfoundland Power's T&D equipment is over 40 years old indicating that some equipment is at an age or level of obsolescence where standard inspection, repair, and preventive maintenance activities, by themselves, are not sufficient for maintaining the condition and operating reliability of the aged equipment. To supplement its inspection and maintenance practices, Newfoundland Power's Asset Management Organization has been appropriately applying, on an annual basis, various capital transmission, distribution, substation, and protective relay rebuild and modernization projects, addressing condition, reliability, obsolescence, and operating issues.

3.3. Newfoundland Power completes its transmission, substation, and distribution inspection and maintenance work in a reasonably timely fashion.

Newfoundland Power schedules corrective maintenance repairs based on priorities related to safety and failure risk in a manner that conforms to good utility practices. It repairs defects with safety or imminent failure risk immediately and it plans other repairs under its various capital projects during the same year or during the following year or years based on priorities.

Newfoundland Power normally completes its inspections, corrective maintenance work, and preventive maintenance work consistent with its schedules, although it defers completion of some lower priority repair work a year or more so that the work can be efficiently clustered with annual capital projects. The Company, however, had to defer some substation transformer, circuit breaker, and relay preventive maintenance work in 2011 and 2012 because of the resources required to address system damage caused by the severe storms occurring during the 2010 through 2012 time period.

Newfoundland Power appropriately uses effective software packages to schedule and track its transmission, substation, and distribution inspection and maintenance work. Newfoundland Power schedules and tracks its transmission, distribution, and substation equipment inspection and maintenance activities, and its T&D vegetation management inspections, using its Avantis work management software application, or subsets of this application.

Transmission line and distribution feeder inspectors, who are also regional planners, use handheld devices to record inspection data and typically download the results of their inspections daily, or when the inspection of a line is complete, into the maintenance management application. Inspectors prioritize deficiencies in consultation with their supervisors. Supervisors, Superintendents, and Regional Managers access the maintenance management data bases to monitor the performance of inspections and the resulting data, and make sure required actions are taken.

Newfoundland Power uses its maintenance software application to schedule and to track its routine substation preventive maintenance work, its monthly substation inspections, and resulting corrective maintenance work to completion. The Asset Maintenance Coordinator, who works in the Substation Operations group, and reports to the Superintendent of System Control and Electrical Maintenance, monitors the substation inspections, corrective maintenance jobs, and routine maintenance status. The coordinator conducts weekly scheduling meetings with regional substation maintenance supervisors and superintendents to discuss and adjust job scheduling and status.

3.4. Newfoundland Power's transmission line and pole inspection and corrective maintenance practices are consistent with good utility practices, except that the Company does not have a program to chemically treat its aged poles. *(Recommendation #3.1)*

Treating poles is a typical utility practice. It can reduce future replacement costs. Newfoundland Power inspects its 2,000 kilometers of transmission line and its more than 24,000 transmission poles on at least an annual basis. Additional unscheduled ground inspections, and sometimes specific detailed climbing inspections and helicopter inspections are conducted to investigate storm damage or operating issues. The Company prioritizes defects identified and schedules corrective maintenance work based on criticality and ability to cluster repairs with budgeted transmission capital projects. Newfoundland Power spends about $2 million per year, more or less, on transmission line inspection and maintenance work, not including equipment replacement and upgrade work conducted under the Company's Transmission Rebuild Initiative.

Inspectors appropriately prioritize deficiencies, and assign repairs in accordance with them. They verify the condition of wood transmission poles through sound and reasonably complete examination practices. Newfoundland Power does not chemically treat its transmission poles to extend pole life because it considers that pole rot and insect infestation is not an issue in the cool Newfoundland climate.

Newfoundland Power's transmission pole replacement rate of about 1.5 percent per year produces replacement of a pole, on average, every 67 years is consistent with good utility practice. Nevertheless, Newfoundland Power would likely reduce future transmission pole replacement costs by implementing a program to chemically treat its aged transmission poles.

3.5. Newfoundland Power's distribution feeder and pole inspections and corrective maintenance practices are generally consistent with good utility practices, except for: (a) lack of periodic sounding (testing for internal decay) of all aged poles, and (b) a slow replacement rate for aged distribution poles. *(Recommendation #3.2)*

Newfoundland Power inspects its each of its 306 distribution feeders (9,000 kilometers) at least on seven-year cycles. Special inspections investigate specific feeder condition and performance issues. Feeder–mounted automatic reclosers and voltage regulators are inspected quarterly.

Newfoundland Power conducts annual infrared inspections of all major distribution equipment. Inspectors sound distribution poles only when a pole appears to be decayed. Newfoundland Power inspects the condition of its distribution poles, but only conducts "sounding" tests (testing for internal decay) when visual observations show the appearance of decay.

Newfoundland Power replaces its distribution poles on average at about 0.5 percent per year. At this rate, Newfoundland Power is replacing each distribution pole, on average, about every 200 years, well in excess of wood pole life expectancy of 40-80 years. Its distribution pole replacement rate should be more in line with its transmission pole replacement rate of 67 years.

3.6. Newfoundland Power's substation inspection, corrective maintenance, and preventive maintenance practices are consistent with good utility practices.

Newfoundland Power's substation maintenance activities are an appropriate mix of time-based inspections and predictive and preventive maintenance activities, and of condition-based major preventive equipment maintenance/overhaul activities, based on inspections, oil tests and other non-intrusive tests, and operating issues, and by the Company's experience with the equipment. Substation technicians conduct substation inspections on a near-monthly basis, including four quarterly *long inspections*. Newfoundland Power also conducts infrared inspections each year. Liberty reviewed the Company's substation electronic substation inspection data sheets and found them appropriate.

Substation inspectors report emergency repairs when a deficiency exists in a substation which is hazardous or might cause an outage. Newfoundland Power spent about $9.7 million in 2013 on substation inspections, corrective maintenance, and preventive maintenance work.

3.7. Newfoundland Power's vegetation management practices are consistent with good utility practices.

Liberty found that Newfoundland Power's vegetation management has been effective. Trees caused only a marginal amount of customer interruptions. Newfoundland Power conducts transmission right of way vegetation and distribution inspections on proper cycles and under an appropriate regimen.

Newfoundland Power spends about $2 million per year on vegetation management (brush clearing, tree trimming, and danger tree removal).

3.8. Newfoundland Power's T&D System Rebuild and Modernizations Strategies are generally consistent with system needs.

Newfoundland Power recognizes that much of the equipment in its T&D system is aged and that its preventive and corrective maintenance activities alone, as good as they are, are not sufficient to assure that its systems approaching end of service life will operate reliably. To supplement its maintenance programs, Newfoundland Power annually budgets various rebuild and modernization capital projects to address transmission, distribution, and substation reliability issues and to proactively address aged equipment condition and obsolescence issues. Annual capital strategies include measures (Transmission Rebuild Strategy, Rebuild Distribution Lines Projects, Distribution Reliability Initiative, and Substation Refurbishment and Modernization

Strategy) well targeted to the needs of its equipment. Asset management strategies have promoted improved system reliability since 1998, while keeping annual capital T&D expenditures under control.

3.9 As indicated in Chapter II, despite notable reliability improvement since 1999 and stable SAIFI and SAIDI metrics exhibited recently, it appears that room remains for improving distribution equipment-caused customer interruptions by applying more weight to the Rebuild Distribution Lines Project. *(Recommendation #2.1)*

Newfoundland Power's system maintenance and capital project practices have resulted in significantly improved SAIDI and SAIFI metrics, excluding major events, since 1998. Newfoundland Power's performance has been even better than Canadian Electricity Association (CEA) composite measures since 2005 for SAIDI and since 2009 for SAIFI.

However, Liberty feels that there is some room for further reducing the distribution system's contributions to Newfoundland Power's SAIFI and SAIDI by installing additional downstream feeder reclosers and applying more weight to its *Rebuild Distribution Lines Project* when prioritizing its annual capital projects. The Company's transmission system and substations contributions have contributed only to small degrees to the overall SAIFI and SAIDI; the majority of the SAIFI and SAIDI have been caused by distribution system-caused customer outages, where additional reclosers can reduce SAIFI and SAIDI.

E. Recommendations

3.1. Unless it can show that fungus and insect infestation does not occur on its wood poles, Newfoundland Power should reconsider the need to treat its transmission poles for fungus and insect infestation, as does Hydro. *(Conclusion #3.4)*

Much of Newfoundland Power's pole plant is aged and applying fungicide and insecticide could extend pole life, reducing the need for capital projects to replace aged poles. Newfoundland Power, however, indicated that the treatments were not necessary because of the cool short Newfoundland summers. Newfoundland Power should review the transmission pole testing and treatment studies which have been conducted by Hydro indicating the need to treat its transmission poles. Treating older poles is good utility practice. Treatment extends pole life, thus reducing replacement costs.

3.2. Consider conducting "sounding" tests on all older distribution poles (not just those obviously rotted) when inspecting feeders; reconsider chemically treating distribution poles to extend their lives. *(Conclusion #3.5)*

The Company does not conduct sounding tests on its older distribution poles, as it does on its older transmission poles. Newfoundland Power should not only consider periodically conducting sounding tests on its older distribution poles to identify which poles have internal rot and may be physically weak, but it should also consider treating older poles to reduce future pole replacement costs.

Many utilities use specialized contractors for inspecting and testing poles and for applying chemical treatments to extend pole life. Utilities use these contractors because they free up resources and conduct the pole inspection work effectively for generally less cost than using in-house line personnel. These specialized contractors not only inspect the poles above ground, but also excavate to examine, bore, and treat a pole below ground line, where fungi damage often occurs. Some utilities also find that installing reinforcing devices on some weak poles save the cost of replacing the poles.

IV. Power Systems Operations

A. Background

An electric utility's power system operation functions include monitoring, managing, and controlling the electric systems under normal and abnormal weather and operating conditions, dispatching trouble call responders, and assisting with keeping customers informed of service outage situations. Power system operators use supervisory control and data acquisition ("SCADA") and other software applications to identify operating constraints on the systems, manage customer outages, and direct safe switching operations. Liberty reviewed Newfoundland Power's system operations facilities, staffing, and training. This chapter discusses the functionality of SCADA and other software applications for predicting loading or voltage constraints, managing customer outages, directing switching operations, and communicating outage information to customers. Liberty also reviewed interaction between Newfoundland Power and Newfoundland and Labrador Hydro.

B. Chapter Summary

Newfoundland Power's System Control Center operates soundly, and with an appropriate number of qualified staff. Adequate measures have been taken to support continued operations should the Control Center not be in service. Using a Central Dispatch Team for dispatch, allows system operators to focus on operations, switching, and other normal and emergency responsibilities. System Operators directly monitor and control the transmission system and most of the distribution system via SCADA.

Liberty did determine that Newfoundland Power needs to: (a) provide for operator training on a console programmed to simulate various system events, and (b) enhance its ability to forecast next 1-to-3 day demands.

C. Findings

1. System Control and Central Dispatch Center Operations

The System Control Center comprises Newfoundland Power's[101] electric system operating facility. It operates from a dedicated, physically secure office. Power System Operators control and monitor Company generation, transmission and distribution systems including equipment loads, bus voltages, and device status via SCADA system. Linkages between Newfoundland Power's and Hydro's SCADA systems allow Newfoundland Power[102] to monitor, but not control the status of Hydro's generating and key interconnection facilities. Four operator consoles are located on the floor, with two staffed at all hours. During storm or emergency situations, the other two positions can be staffed as needed. A fifth console located on an upper floor can support training, but the Company has no dedicated training console. Three other facilities can serve temporarily, should the System Control Center become inoperable or inaccessible. Newfoundland Power has a dedicated fiber-optic loop, redundant servers and power back-up.

[101] Liberty on site visit, 19 September 2014.
[102] Response to RFI #PUB-NP-247.

The SCADA system monitors demand in real time. Telemetry data from the Hydro infeed points comes via the Inter-Control Center Communications Protocol ("ICCP") link between Hydro's Energy Management System and the SCADA system. Adding the total system infeed value from Hydro to the Company's total generation value calculates the instantaneous total system demand. Newfoundland Power[103] and Hydro worked together to bring more real-time operating data into the Control Center. Newfoundland Power now has full information on the status of Hydro's generating stations, total Island Interconnected System ("IIS") load, and major terminal stations that supply Newfoundland Power load.

The System Control Center[104] also directs switching of energized equipment by field forces, which allows workers to de-energize facilities required safely to maintain or repair equipment. Newfoundland Power uses a worker protection permit system (based on the tagging of devices) that must undergo a status change after initiating worker protection. Field workers place tags on any device opened for providing safety clearances. SCC operators simultaneously apply corresponding electronic tags on the switching devices shown on the Company's SCADA system. Devices tagged on the SCADA system cannot be operated remotely from SCADA or have their status manually updated on SCADA while the SCADA tag remains in place.

Newfoundland Power's[105] Central Dispatch Team manages the scheduling and dispatch of field crews during regular working hours, except when safety issues and other high priority issues require dispatch from the Control Center. The Central Dispatch Team ensures efficient work scheduling. This Team forms part of the Company's recently adopted method for dispatching transmission and distribution line work. Newfoundland Power has deployed mobile computing in all of its line trucks, implemented a computerized operations dispatch system, and expanded the use of its geographic information system.

Newfoundland Power's Customer Contact Center receives customer trouble calls during normal working hours (8:00 am to 5:00 pm, Monday through Friday). The Central Dispatch Team dispatches work arising from customer trouble calls received between 8:00 am and 4:00 pm. Off-hour trouble calls route to the System Control Center, which the Company staffs 24 hours every day of the year.

During large storms or major electrical system events, the Contact Center and Central Dispatch Team typically operate on extended hours, receiving and dispatching work associated with customer trouble calls. This function permits System Operators to focus on power system restoration.

2. Control Center and Central Dispatch Team Staffing

The four[106] Lead Power System Operators have an average of 25 years of experience, and the six Power System Operators average 11. Efforts to secure replacements begin within a year of expected retirements. As do most utilities, Newfoundland Power seeks applicants with 10 to 12

[103] On site meeting, 19 September 2014.
[104] Response to RFI #PUB-NP-261.
[105] Response to RFI #PUB-NP-254 and 260.
[106] On site meeting 19 September 2014.

years of field experience to promote into the Power System Operator positions. The smaller Central Dispatch Team[107] includes 5 Operations Coordinators.

Control Center staff operates on a dual 12-hour shift basis to provide continuous staffing.[108] Each shift includes an experienced Lead Power System Operator and one or two Power System Operators. The Supervisor of System Control, the Superintendent of System Control and Electrical Maintenance, and the SCADA Team provide technical support and guidance to the system operations teams.

3. Power System Operations' Management Tools

SCADA serves as the primary tool for Power System Operators. There is no dedicated SCADA training console. A fully functional SCADA outside the control room, however, is available for training use.[109] The primary software tools used by the Central Dispatch Team include ClickSoftware. This application permits the Central Dispatch Team automatically to schedule work for power line technician crews. A schedule optimizer reduces driving time, and increases overall efficiency by automatic work schedule creation that considers skill, location, and priority factors. The software tracks work progress as field crews update job status from laptops in the field.

Operators use SCADA to monitor and control remotely 71 substations, 25 hydro generators, 2 gas turbines, 187 distribution feeders and 78 power transformers. Engineering and operations employees also use real-time and historical data from the SCADA system for system assessment, analysis and planning purposes. The SCADA system monitors and controls a total of 40,000 individual data points. Ninety percent of transmission lines and 60 percent of distribution feeders (61%) have SCADA-controlled circuit breakers or reclosers.[110] Operators monitor system power frequency via a SCADA under-frequency load-shedding application. Such monitoring permits operators to feeders following an under-frequency event. Newfoundland Power[111] plans to upgrade its SCADA system, and place all feeders under SCADA control by 2016.

Energy Management Systems operate on top of a SCADA platform to monitor, control and optimize the performance of generators and transmission networks. Typical applications include automatic generation control, unit commitment, state estimator, online three-phase load flow, load forecasting and a dispatcher training simulator. Newfoundland Power[112]does not have its own Energy Management System. It does not foresee the need for such applications, given its planned SCADA replacement. Newfoundland Power has included custom applications within its SCADA system to support operation of the small hydro plants and the distribution system.

Newfoundland Power, however, links its SCADA system to Hydro's energy management system. This link provides each utility with near real-time information concerning each other's

[107] Response to RFI #PUB-NP-254.
[108] On site meeting 19 September 2014.
[109] Response to RFI #PUB-NP-253.
[110] Response to RFI #PUB-NP-149 and 245.
[111] Response to RFI #PUB-NP-265.
[112] Response to RFI #PUB-NP-257.

electrical operations on the IIS. Communication and coordination between Newfoundland Power's SCC and Hydro's ECC is continuous and is the central feature of daily operational coordination on the IIS. This link ensures that routine daily electrical system operations such as generation dispatch and switching procedures are performed on a safe and reliable basis.

The ARC-FM GIS application displays information about the geographic location and electrical connectivity of the distribution network. The System currently stores information about primary distribution lines, streetlights, and poles. This information includes equipment specifications and geographic location. Newfoundland Power installed the System in 2013 as part of a project to streamline the manual processes used to maintain and distribute distribution asset information.

4. Short-Term Forecasting

Power System Operating departments generally develop short-term load forecasts that cover the next day and up to three days. These forecasts help operators to schedule generation, identify facilities that can be taken out of service under low load periods or returned to service (or denied an outage) for higher than expected loads. Sophisticated tools exist to perform this function, but many smaller utilities use manual methods. A manual process might proceed, for example, by examining the typical daily load curve for the next day, based on the day of the week and season, and then applying local knowledge of weather effects. Newfoundland Power[113] does not have an operations tool to produce its own daily load forecasts. It does not see the need for one, because it believes it can gauge short-term needs based on experience and engineering judgment, or as provided to them by Hydro. These circumstances have led Newfoundland Power to conclude that it cannot justify the expense of an EMS application to provide short-term forecasts.

5. Load Management Tools

a. Conservation and Curtailment

Newfoundland Power[114] has some means to control its daily peak demands when generation supply is insufficient. It undertook in December 2013 and January 2014, and other times, customer energy conservation initiatives to minimize activating automatic underfrequency load shedding and the need to conduct rotating feeder outages. Newfoundland Power's[115] approach is to: (a) reduce energy usage at its own facilities, (b) issue energy conservation advisories and energy reduction instructions to residential, commercial, industrial, and other customers via all media forms and its website, and (c) if necessary, shed commercial customer loads after one-hour notice for those customers who have opted for the Curtailable Service Option ("CSO") billing rate.

Newfoundland Power[116] is not able to estimate the effectiveness its customer energy conservation measures for reducing demand, but does know that curtailments have reduced demand between 7.0 and 8.5 MW. During 2013, Newfoundland Power[117] requested customer curtailments a total

[113] On site interview 19 September 2014.
[114] Response to RFI #PUB-NP-014.
[115] Response to RFI #PUB-NP-014.
[116] Response to RFI #PUB-NP-014.
[117] Response to RFI #PUB-NP-085.

of 13 times. Eight of these times were to manage demand related costs and the other five times were on the behalf of Hydro to support the IIS. The durations of these curtailments were from one to three and one-half hours.

b. Voltage Reduction

Newfoundland Power[118] has the ability to temporarily reduce load by reducing voltage to about 186,000 (73 percent) of its customers. Newfoundland Power[119] can exercise voltage reduction by requesting Hydro to adjust voltage at the interconnection terminal stations, via the SCADA control of voltage regulating equipment in fourteen substations, or by manually readjusting voltage regulating equipment in its substations where the transformers have on-load tap changers and where generation or feeder length do not preclude reducing voltage. When Hydro reduces system voltage, it does so in two steps -- a three percent reduction followed by a two percent reduction. If Newfoundland Power reduces voltages at various substations, it is initially at two or three percent then up to seven percent, depending on feeder characteristics.

Newfoundland Power reported that it can reduce peak demand on about 1,005 MW of its 2013 peak demand of 1,378 MW. [120] The Company estimates that a five percent voltage reduction causes an immediate load reduction of about 66 MW and a sustained load reduction of about 26 MW. Newfoundland Power[121] exercised voltage reduction on eleven occasions during 2013. Eight of these occasions were to manage demand costs and three were occasions at the request of Hydro to support the IIS.

c. Automatic Underfrequency Load Shedding

Newfoundland Power's[122] distribution protective relay system is programmed so that whenever system demand or the availability of generation causes reduced system frequency (which could cause system collapse) some customer load will be shed (by tripping distribution feeder reclosers at the substations) to protect the integrity of the IIS. Following such an event, Hydro's Energy Control Center cooperates with Newfoundland Power's SCC to ensure that customers disconnected from the system are reconnected to the system quickly, while maintaining system integrity.

Newfoundland Power has underfrequency relays controlling 168 out of its 306 feeders. A feeder must have remote control capability and a minimum of 2 MW of estimated peak load to be considered for underfrequency tripping. Feeders with critical customers such as hospitals are not included. Following an underfrequency event, the feeders that were impacted by the trip are rotated with others that have not been recently impacted. This helps to share the burden of these outages among all customers. Newfoundland Power's underfrequency trip groups have a total of 482 MW of estimated peak load. Table 4.1, below, shows the power frequency at which each of the trip groups operate and the estimated peak load of each group. The "Group 1" frequency trigger at 59 Hz includes a 15-second delay.

[118] Response to RFI #PUB-NP-087.
[119] Responses to RFIs #PUB-NP-091 and 092.
[120] Response to RFI #PUB-NP-088.
[121] Response to RFI #PUB-NP-090.
[122] Response to RFI #PUB-NP-002.

Table 4.1: Underfrequency Trip Groups

Group	Frequency (Hz)	Estimated Peak Load (MW)
1	59.0[1]	40
2	58.8	34
3	58.6	43
4	58.4	56
5	58.2	60
6	58.1	90
7	58.0	159

6. Rotating Outages During the January 2014 Generation Insufficiency Event

The purpose of conducting rotating feeder outages is to prevent uncontrolled collapse of the system and to minimize the effect on customers during generation deficiencies. These outages proactively reduce small blocks of load for one-hour periods before automatic underfrequency load shedding occurs and before total system collapse. During the period from January 2 to January 8, 2014, [123]as customer demand approached the limit of available generation, small blocks of customer load were rotated off the system to match load with available generation. While monitoring system frequency and voltage levels, Newfoundland Power rotated additional small blocks of load on and off. Newfoundland Power's goal was to limit rotating power outages for each feeder to one hour. Operational difficulties, such as cold load pick up issues, however prevented restoring some feeders within one hour. Newfoundland Power could not provide its customers with specific advance notice of the precise timing and location of rotating power outages because of the quickly changing needs to reduce demand occurring during the January 2 through 8, 2014 time period.

Newfoundland Power[124] indicated that the impact on customers of any future need for conducting rotating outages would be reduced if: (a) it had real-time IIS generation and demand data from Hydro prior to a generation shortfall event, and (b) more feeder automation (downstream reclosers) was installed to provide remote controlled feeder sectionalizing. Newfoundland Power[125] plans to install more downstream reclosers in 2015 to provide better sectionalizing of some highly loaded feeders.

[123] Response to RFI #PUB-NP-022.
[124] Response to RFI #PUB-NP-049.
[125] Response to RPI #PUB-NP-024.

7. Coordination between Newfoundland Power and Hydro

Among other things, Newfoundland Power[126] and Hydro communicate with respect to load forecasting and planning of major electrical system modifications. They also communicate on an ongoing basis in relation to the coordination of activities related to capital work and maintenance of major system components and to operational coordination of response to storms and other events affecting the system. Communication with respect to the various matters takes place on an ongoing basis as required between personnel at various levels of the two utilities.

Oversight of matters of joint concern related to system reliability is the responsibility of the Inter-Utility System Planning and Reliability Committee. The Committee includes senior operations and engineering management from Newfoundland Power and Hydro, and meets regularly to consider matters related to system reliability, including reliability targets, system contingency and restoration planning, generation availability and peak load management preparedness.

Newfoundland Power and Hydro coordinate scheduling of work on their respective systems. This is done for two basic reasons. One is to ensure that one utility's actions will not unnecessarily affect the other utility's provision of service to its customers. The other is to ensure that the joint actions of the two utilities are undertaken in a way which is least disruptive to the reliable delivery of electricity to customers. Coordination of planned outages on the IIS requires a high degree of communication and cooperation. The Inter-Utility System Planning and Reliability Committee provide oversight of how the utilities communicate and cooperate.

8. Energy Management

Newfoundland Power[127] monitors its own demand, which comprises about 85 percent of the total demand on the IIS. Newfoundland Power's[128] System Control Center operates SCADA that allows it to monitor and control Newfoundland Power's generation, transmission and distribution systems. For daily operational coordination, Hydro's Energy Control Center monitors and controls its generation and bulk transmission system. The Center's primary functions comprise economic dispatch of generation and ensuring the balance of electrical system supply and demand for the IIS. Newfoundland Power and Hydro both staff their control centers [129] all the time.

Newfoundland Power's[130] SCADA system links with Hydro's Energy Management System. Newfoundland Power's SCADA monitors 754 unique data points exchanged through the Inter-Control Center Communications Protocol link to Hydro's Energy Management System. This total includes approximately 400 data points that first became available in June 2014. There are no outstanding requests for data points to be added to the exchange.

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126 Responses to RFIs #PUB-NP-002 and 042.
127 Response to RFI #PUB-NP-042.
128 Response to RFI #PUB-NP-264.
129 Response to RFI #PUB-NP-002.
130 Response to RFI #PUB-NP-247.

Communication[131] and coordination between Newfoundland Power's SCC and Hydro's ECC is intended to be continuous. It comprises a central feature of daily operational coordination, with the purpose to ensure that routine daily electrical system operations such as generation dispatch and line and equipment switching are performed on a safe and reliable basis.

Hydro[132] had not provided Newfoundland Power with real-time demand and generation reserve information on the IIS until the end of September 2014. A new joint utility protocol now calls for informing Newfoundland Power of real-time IIS demand and generation reserve information (and for providing additional EMS data points). The fact that Newfoundland Power did not have direct access to real time IIS operating status was typically of little consequence during normal conditions when Hydro's generation reserve is sufficient. However, on the occasions when Hydro's generation reserves were not likely to meet the demand such as during the January 2014 events, Hydro had not contemporaneously provided Newfoundland Power with demand and generation reserve information. Also, Hydro did not work closely with Newfoundland Power in a timely fashion prior to the January 2 event to address demand relief solutions, and to agree on joint actions for requesting conservation measures and for informing both utilities' customers of where and when outages might occur and when outages are expected to end.

D. Conclusions

4.1. The System Control Center is appropriately equipped and backed up by two other locations.

4.2. Although the SCC has a control console used for one-on-one training, it does not have software for simulating the electric systems under normal and emergency conditions. (*Recommendation #4.1*)

Newfoundland Power uses a spare, but active monitor where a trainee can view application screens. Newfoundland Power does not have a software application that allows a trainee to practice dealing with programed simulated system event scenarios. For some utilities, the energy management systems can be programmed to provide training simulations. However, Newfoundland Power does not have such a system.

4.3. Newfoundland Power's use of its Central Dispatch Team to relieve the System Control Center of duties for managing and dispatching planned work and trouble call crews during regular hours and emergencies is a sound practice.

The separation of duties allows System Operators to focus on operating Newfoundland Power's electric systems and on supervising switching procedures, while the Central Dispatch Team's focus is on customer service and on scheduling work efficiently. Also, Newfoundland Power has provided its crews with laptop computers containing geographic information system data for trouble call locations and with work management applications for trouble call action reporting. It also can track crew locations, via Global Positioning System, to more quickly dispatch the nearest crews to trouble calls.

[131] Response to RFI #PUB-NP-002.
[132] Hydro's November 21, 2014 Updated Integrated Action Plan as of the end of October 2014.

4.4. The System Control Center and the Central Dispatch Team are appropriately staffed.

Newfoundland Power's four lead system operators and six power system operators have substantial experience. Shift teams are appropriate.

4.5. Newfoundland Power appropriately monitors its transmission system, its infeed points from Hydro, and Hydro's generation via a link between Hydro's Energy Management System and Newfoundland Power's SCADA system.

4.6. The planned replacement of Newfoundland Power's SCADA system and its Outage Management System should improve the effectiveness of its system operations.

The new system will be designed to be capable of advanced distribution management functions including interfaces with the Geographic Information System and to a new commercial Outage Management System. Its current Outage Management System will be replaced with an advanced commercial system.

4.7. The System Control Center and the Central Dispatch Team appropriately use software tools for managing system operations.

Newfoundland Power's System Control Center controls and monitors its transmission system and much of its generation and distribution system with its SCADA system. The Outage Management System provides support to staff who create, process, dispatch, and close out outage reports. Other systems adequately support the variety of functions required to be performed.

4.8. Newfoundland Power's SCC does not have an Energy Management System because it links its SCADA system to Hydro's EMS.

This link provides each utility with near real-time information concerning each other's electrical operations on the IIS. Communication and coordination between Newfoundland Power's SCC and Hydro's ECC is continuous and is the central feature of daily operational coordination on the IIS. This link ensures that routine daily electrical system operations such as generation dispatch and switching procedures are performed on a safe and reliable basis.

4.9. The System Control Center does not have an operations software tool for producing daily forecasts. (*Recommendation #4.2*)

The Center depends on 1-3 day forecasts based on operations/engineering judgment and on short-term forecast provided by Hydro. Liberty found Newfoundland Power's current software and other applications used for the daily operation of the Company's system to be appropriate. The Company's recognition of the need to integrate the various operations applications into more holistic SCADA and OMS packages is also sound. The Company is going in the right direction with the exception of ceding the short-term forecasting function to Hydro's Nostradamus system.

4.10. If Hydro had timely consulted with Newfoundland Power about solutions for mitigating Hydro's generation shortfalls, Newfoundland Power would possibly have been better able to mitigate the issue with voltage reductions and load curtailments.

Hydro did not work closely with Newfoundland Power in a timely fashion prior to the January 2, 2014 event, to jointly discuss IIS demand relief solutions, and to agree on joint actions for requesting conservation measures and for informing both utilities' customers of where and when outages might occur and when outages are expected to end.

Although the communications and coordination between Newfoundland Power and Hydro appear to be adequate for normal operations, during the January 2014 outages Hydro did not confer with or provide Newfoundland Power with timely communications related to joint mitigating actions, and it did not provide accurate real-time information about short-term load demand and generation capacity shortfalls when these issues arise, such as prior to the January 2, 2014 generation shortfall.

E. Recommendations

4.1. Include in the specification for the new SCADA system the ability to turn an operator console into a formal training system simulation console for instruction and evaluation. (*Conclusion #4.2*)

4.2. Consider including a short-term forecasting application, if possible, when it replaces its current SCADA system. (*Conclusion #4.9*)

V. Generation

A. Background

Newfoundland Power purchases most of its energy from Newfoundland and Labrador Hydro (Hydro), but its hydroelectric and thermal generating units have the capability to produce a small portion of its energy and peak demand requirements. Liberty reviewed how Newfoundland Power operates and maintains its generating units and whether its practices are consistent with the needs of the electric system and with good utility practices.

Newfoundland Power[133] can generate about 139 MW from its own generating units. These resources include[134] 23 small hydroelectric plants, ranging from less than 1 to slightly more than 10 MW. The total output of Newfoundland Power's hydroelectric generators is 97.516 MW. Another 41.5 MW comes from two 2.5 MW diesel-fueled generators (one portable) and three gas turbines (20 MW, 10 MW, and 6.5 MW).[135] The hydroelectric facilities range in age from 15 to 114 years. Its gas turbine generators range in age from 39 years to 45 years.

B. Chapter Summary

Newfoundland Power has been appropriately operating and maintaining a fleet of aged generation units. Its generation maintenance strategy seeks to employ inspection and maintenance practices and refurbishment projects that will maintain, on average, a minimum availability of at least 95 percent. It has studied and is taking actions to address issues that affected the availability of hydroelectric and thermal units during the January 2014 system events. Except for a few small units, Newfoundland Power's generation units are either automatically controlled, or controlled by the System Control Center.

C. Findings

1. Generation Availability during the January 2014 Outage Events

Several Newfoundland Power[136] thermal generators were out of service for more than one day during the January 2 – 8, 2014 time period. One 2.5 MW diesel generator was out of service during the entire period because bearings were being replaced. The other 2.5 MW diesel generator was taken out of service on January 6, because of bearing damage. The Wesleyville 10 MW gas turbine was out of service from January 5 through January 22, because of a lube cooler oil leak. The Greenville 20 MW gas turbine ran out of fuel for most of January 3 and 4. Weather conditions prevented Newfoundland Power from supplying fuel to the gas turbine.

About 10.48 MW of hydroelectric generation was out of service during this same period. The Tors Cove G3 2.4 MW generator was out of service because of an AC drive failure beginning on January 6. The Westbrook 0.68 MW generator was out of service for a bearing failure and the

[133] Responses to RFIs #PUB-NP-033, 036, 038, and 171.
[134] Responses to RFIs #PUB-NP-001 and 056.
[135] Response to RFI #PUB-NP-001 and Newfoundland Power 2015 Budget Application.
[136] Responses to RFIs #PUB-NP-001, 039, and 180.

Rattling Brook G1 7.4 MW generator was out of service because of a damaged rotor pole. The last two were out of service for the entire January 2 through 8, 2014 time period.[137]

Experience from the 2013 and 2014 outage events led Newfoundland Power[138] to consider changes in the operation of its hydroelectric and gas turbine generating facilities. Hydro requested operation of Newfoundland Power hydro units for periods much longer than usual. Extended usage reduced water resources for some of the facilities. Hydro also requested continuous operation of the 20 MW gas turbine generator. The unit ran out of fuel after 39.5 hours of operation. Winter storm conditions prevented timely replenishment of fuel supply.

Following the January 2014 events, Newfoundland Power[139] decided to enhance winter-season generation availability by increasing water storage for hydro units and fuel storage for thermal ones. It also decided to conduct reliability assessments of its thermal generating plants.[140] Inflows[141] to Newfoundland Power's hydroelectric storage and river systems fall during winter months. Increasing water storage at existing facilities prior to winter season will require an examination of water management practices to address increased risk of spilling. A solution may lie in increasing the number of dams or increasing the height of existing dams.

2. Generation Availability

Newfoundland Power's[142] 32 hydroelectric generating units were available, on average, for 96.6 percent of the time during the 2009 to 2013 five-year time period and 95.5 percent of the time during the winter of 2013. Newfoundland Power's hydroelectric units had an average capacity factor (percentage of running at full capacity all year) of 51.1 percent during the 2009 to 2013 five-year time period and 62 percent capacity factor during the 2013 winter season.

3. Generation Operations

Generating units with remote control capability can be operated remotely, when necessary, by Newfoundland Power's System Control Center (SCC) Power System Operators via the Company's SCADA system. Generating units that are not remotely controlled are manually controlled by local operating staff under the direction of SCC Power System Operators.

Of the 32 hydroelectric units, 24 have remote control capability. The remaining hydro units possess generator breaker indication and limited telemetry. Of the eight hydroelectric units where full remote control is not available, two are third units at a three-unit plant. The other two units, given available water supply, are sufficient for most of the year. The remaining six units range from 255 kW to 680 kW, which makes them too small to justify full automation. The gas turbine generators at Greenhill and Wesleyville possess remote control capability. The mobile gas turbine and the mobile diesel generator units can provide indication of a limited set of points

[137] Response to RFI #PUB-NP-001.
[138] Response to RFI #PUB-NP-036.
[139] Response to RFI #PUB-NP-036.
[140] Liberty meeting with Newfoundland Power on September 19, 2014.
[141] Response to RFI #PUB-NP-056.
[142] Response to RFI #PUB-NP-177.

(for example generator breaker and unit lockout) when installed at substations and plants where SCADA monitoring and control is available.

Sixteen of the hydro plants use local programmable logic controllers (PLCs) to run water management algorithms that automatically determine optimal unit operation. Power System Operators can adjust water management systems to control how the logic controllers operate the hydro plants.

4. Generator Maintenance

Newfoundland Power's[143] generating plant preventative maintenance activities fall under the responsibilities of plant operators, maintenance staff, engineering staff, and consultants. Planners schedule, track, and monitor completion of maintenance activities using maintenance management software. The Company conducts regular inspections of dam, plant, and generator equipment on predetermined cycles. It uses predetermined cycles for preventive maintenance and testing work as well.

Corrective maintenance needs identification comes from inspections and observations of operating anomalies. Priorities govern the order of repairs:

- Priority 1 – Very High Priority – one month or sooner
- Priority 2 – High Priority – three months
- Priority 3 – Medium Priority – six months
- Priority 4 – Low Priority – one year.

Newfoundland Power's Superintendent of Generation and Substation Operations and the maintenance supervisors have the responsibility to ensure completion of all corrective maintenance on schedule and as defined.

The rate of completion of maintenance work has declined, as the following tables demonstrate.[144] Newfoundland Power indicated that all backlogged preventive maintenance tasks were either completed or rescheduled in the following year. It expects to timely complete the remaining preventive and corrective maintenance orders scheduled for 2014.

Table 5.1: Preventive Maintenance Performance

Work Orders	2010	2011	2012	2013	2014 (YTD)
Completed	11,945	1,995	1,922	1,880	975
Backlogged	157	229	280	312	282
Completed	92.50%	89.70%	87.30%	85.80%	77.60%

Table 5.2: Corrective Maintenance Performance

Work Orders	2010	2011	2012	2013	2014 (YTD)
Completed	120	90	83	73	55
Backlogged	5	3	4	7	26
Completed	96.00%	96.80%	95.40%	91.30%	67.90%

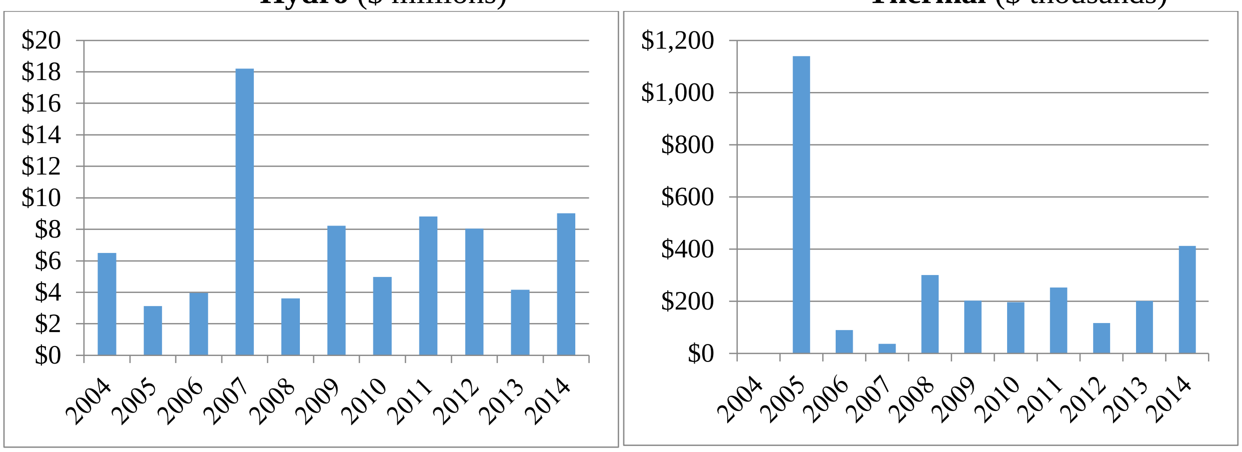
[143] Response to RFI #PUB-NP-175.
[144] Response to RFI #PUB-NP-176.

5. Capital Refurbishment

The average age of Newfoundland Power's 23 small hydro plants is 71 years and its five thermal plants, including the mobile unit, have an average age of 36 years. Refurbishment of aging assets thus drives much of the capital budget for generation. Generation capital refurbishment programs involve considerable capital expenditures on an annual basis as in-service assets deteriorate with age and service. The next chart shows[145] hydro and thermal generation plant capital expenditures over time. The amounts reflect annual authorizations; 2014 amounts are forecasts. Large 2007 hydro expenditures were influenced by the ($18,242,000) Rattling Brook Hydro Plant Refurbishment Project. The large expenditures in 2005 for thermal plants reflect refurbishment of the Mobile Gas Turbine and the purchase of the Portable Diesel unit.

Chart 5.3: Generation Capital Expenditures

Hydro ($ millions) **Thermal** ($ thousands)



6. Spare Parts

Newfoundland Power[146] maintains a substantial quantity of spare parts on hand (about 900) for its generating equipment. Some of the replacement parts for the old facilities are not available. At times, Newfoundland Power must make modifications to the facilities to make use of modern replacement systems and parts. The maintenance personnel responsible for generator maintenance are responsible for routinely replenishing the Company's spare generator facility parts inventory.

D. Conclusions

5.1. Newfoundland Power has appropriately operated and maintained its generating units.

Newfoundland Power conducts inspections at its generating stations on daily, weekly, monthly, bi-monthly, and semi-annual bases. Although Newfoundland Power backlogs some corrective maintenance work, it completes the work during the following year. Newfoundland Power undertakes generation repair, rehabilitation, and production improvement work on an

[145] Response to RFI #PUB-NP-174.
[146] Response to RFI #PUB-NP-033.

appropriately planned basis. The ages of Newfoundland Power's generating units appear likely to require increasing maintenance costs as time passes.

5.2. Newfoundland Power has maintained a reasonable level of generating availability.

Hydro units averaged 96.6 percent availability from 2009 through 2013, and 95.5 percent during the winter of 2013.

5.3. Newfoundland Power has analyzed and is addressing issues, such as water and fuel supply, that may enhance the capacity it can make available to the Island Interconnected System during periods of generation shortage.

5.4. Newfoundland Power can control its larger units through SCADA or other automatic means.

E. Recommendations

Liberty has no recommendations related to Newfoundland Power generation.

VI. Outage Management

A. Background

Liberty examined Newfoundland Power's outage management approach, organization, resources, practices, and activities. The review included field personnel available to respond to trouble calls, and the receipt, location, and tracking of trouble calls. Liberty examined Newfoundland Power's Outage Management System (OMS), training to use the system, and the use of outage cause codes to improve system performance. The examination also addressed the basis for estimating and communicating estimated restoration times following outages.

Outage Management Systems play a critical role in response to storm-related outages. Many utilities struggle with Outage Management System performance, reliability, and usage during large events and storms. Systems that perform with great effectiveness during small events can degrade and even collapse under the stresses of major outages. When they do, distribution field personnel must revert to manual processes that further burden and delay outage response.

B. Chapter Summary

Newfoundland Power has stationed throughout its serving area sufficient numbers of outage responders trained to report outages for analysis for reliability reasons. The Company provides customers with options for reporting outages and it provides estimated restoration times to customers. Newfoundland Power, however, does not know the accuracy of the estimates it provides. While the Outage Management System serves the system adequately, the Company plans to replace the in-house system with a more effective, commercially available one, within five years. The new system will better integrate with a new SCADA system (due for installation in the next two years or so) and with other applications used to operate the electric systems.

C. Findings

1. Outage Response Staffing

Newfoundland Power operates under a[147] goal to respond to customer outages within two hours. During normal work hours, the Company assigns 12 Supervisors and 27 Power Line Technicians (PLTs) operating out of the three regional offices, plus 19 technicians operating out of its ten remote districts, to respond to trouble tickets. The Company also assigns shift crews, to respond to trouble calls from 8:00 am to midnight, seven days a week in the St. John's region. A total of 7 Supervisors, 12 regional and 7 district Technicians remain on standby to support outage response after-hours.

2. Outage Reporting

Newfoundland Power[148] provides customers several options for reporting outages and obtaining outage restoration information. Customers can call the Customer Contact Centre (CCC) using the Company's toll free number or they can use the *Report Power Outage* function available on the

[147] Responses to RFI #sPUB-NP-152 and 154.
[148] Response to RFI #PUB-NP-095.

Company's website. When the customer reports an outage on the phone, the Customer Account Representative (CAR) uses call screening guidelines to determine whether the customer is calling about an outage the Company may already be aware of, or whether the customer is calling about an outage which has not yet been logged. If the customer identifies a new outage, the CAR will create an outage ticket to record the details of the outage in the Company's Outage Management System. The CCC operates from 8:00 am to 5:00 m, Monday to Friday. After normal business hours customer calls are answered by the System Control Centre except in major outage events where the CCC is staffed outside normal business hours.

Newfoundland Power's[149]inbound call system has the capability of providing customized messages to one of eight districts within the Island Interconnected System, based on the telephone exchange of the incoming call. Tailored messages regarding acknowledgement of an outage, status of the response, and estimated restoration times can precede the transfer of the call to the CAR.

When a customer uses the *Report Power Outage* function on the Company website, the customer is presented with a series of questions to determine whether the customer's situation warrants that a new outage ticket needs to be created, or whether the outage is already known by the Company.

Customers can obtain outage restoration information via the Company's High Volume Call Answering (HVCA) system, the Company's website, or through a CAR. The outage restoration information customers receive via these channels originates with the Company's Outage Management System. Customers can also report outages and obtain outage restoration information on Newfoundland Power's Twitter feed and Facebook page. These are used to share outage event information with customers, and include links back to the Company's website.

3. Response to Outages

Customer account representatives or Power System Operators generate outage tickets[150] using the Outage Management System. The system transmits outage tickets electronically to trouble response crews consisting of two Power Line Technicians. The crews receive the tickets via computers in the line trucks. Geographic Information system transponders in the trucks expedite response. The Central Dispatch Team or the System Control Center monitors trouble crew locations, and dispatches the available line crew closet to the outage. Senior engineers and technologists review the outage causes and numbers of customers interrupted to identify possible responsive actions.

4. Outage Management System

The Outage Management System creates, processes, dispatches, and closes outage reports from customers. The system also maintains records of outage calls and response times and records interruption reports for managing reliability statistics. A series of 2012 enhancements to the internally developed system: (a) allow customers to report outages via the website or mobile

[149] Site visit 19 September 2014.
[150] Response to RFI #PUB-NP-154.

devices, (b) improved functionality for grouping and assignment of related outage tickets, and (c) integrated with the scheduling and dispatch software to provide for electronic dispatch and completion of outage tickets in the field via a mobile computing application.

Unavailability of the[151] Outage Management System has been nominal since 2009. The System was unavailable for approximately two hours due to unplanned issues that required support and maintenance. The Information Services department supports and maintains the Outage Management System.

Newfoundland Power expects to replace its existing Outage Management System with a commercial alternative within five years. Modern outage management systems provide more advanced functionality through integrations with SCADA systems and geographic information systems. This functionality includes predictive analysis and automatic grouping of related outage calls, as well as automatic customer outage notifications.

5. Outage Management System Training

Newfoundland Power's experienced senior employees provide Outage Management System training to new employees in the Customer Contact Center (CCC) and System Control Center (SCC), as part of new employee orientation[152]. Newfoundland Power's line staff received training on the ClickMobile application when it was initially installed on the laptops in their vehicles and again when software upgrades are implemented.

Newfoundland Power also conducts periodic Outage Management System refresher training. When enhancements are made to the Outage Management System, training is included as part of the project plan. This training is led by employees who have been involved in the design and testing of the enhancements. In preparation for severe weather events occasional Outage Management System users that assume a customer service role as part of the storm response will typically receive one-on-one training from employees experienced with the system. These employees also have access to an on-line training document that can be referenced from within the application.

6. Outage Cause Codes

Newfoundland Power codes outages under 28 Canadian Electricity Association (CEA)-defined categories for entry[153] into the Outage Management System by the Power Line Technicians who identify outage causes. When applying outage cause codes through mobile computers, technicians can provide additional outage cause details, and indicate follow up work required. On a daily basis, Newfoundland Power's System Control Center personnel review the accuracy of closed trouble call orders and edit the outage cause code reports and restoration time data. The review also ensures entry of any follow-up work into the appropriate system. All interruption data is also reviewed by Area Superintendents on a monthly basis. Area Superintendents and

[151] Responses to RFIs #PUB-NP-300 & 301.
[152] Response to RFI #PUB-NP-302.
[153] Response to RFI #PUB-NP-154.

Line Supervisors also review outage response times on a monthly basis to identify reasons for delayed response and for determining opportunities for improvement.

A key function[154] of an Outage Management System is to collect outage data and cause codes to develop reliability indices. These data are used to evaluate and report on reliability performance, and to help asset management and system planners allocate assets appropriately.

Newfoundland Power's Outage Management System contains a database with a user interface to allow customer interruptions to be entered, saved, and edited. Reporting functionality within the Outage Management System provides the ability to directly report standard customer based reliability data corporately, by region or by feeder. Current and historical data can be reported for SAIDI, SAIFI, CAIDI, CAIFI, customer minutes of interruption and customer interruptions.

7. Estimated Restoration Times

Newfoundland Power uses its Outage Management System to log customer reported power and street light outages, via telephone or the Company's website, and to electronically dispatch outage tickets to crews located in the field.[155] The outage tickets dispatched by the Outage Management System are then completed electronically by the crews. Outage tickets might be for individual outages or for grouped outages as occurs during storms.

The Company uses its *Informer Application* to communicate outage information to customers. Outages recorded in the Informer system include details such as the locations affected, estimated restoration time, reason for the outage, and other relevant information. Customers can view this information on the Company's website in a list or map format. Customers can also listen to a recorded message with the same outage information by calling the Company's Customer Contact Centre. During normal system operations, the Informer system is typically updated by staff at the System Control Center. This responsibility is transferred to the Communications Hub during large storms or system events, such as those on January 2-8, 2014.

The typical process for updating Informer with outage information is as follows:

- When the Company becomes aware of an outage, either through indication at the Control Center, reports from operational staff, or though customer calls, the outage will be added to the Informer system.
- If the cause and estimated restoration time are unknown, the outage will initially be listed as "Under Investigation" until the required information is provided by field staff responding to the outage. For the rotating outages during January 2-8, 2014, restoration times were typically listed as one hour.
- Field personnel provide updates to the System Control Center and regional operations regarding estimated restoration times or changes to the locations affected. This information is updated in the Informer system as information becomes available.
- The Control Center or the Communications Hub also monitors the outages listed on Informer, and proactively seek updates from field staff regarding ETR status.

[154] Response to RFI #PUB-NP-306.
[155] Response to RFI #PUB-NP-103.

- When an outage ends, the Control Center or Communications Hub removes the outage data from the Informer system.

D. Conclusions

6.1. The numbers and locations of field personnel assigned to outage response duties are appropriate in meeting outage-related needs.

Trouble call responders are available and appropriately located to timely respond to outage calls. The Company makes assignments with the goal of responding to trouble calls within two hours, designating more than 40 Power Line Technicians in its regions and districts to respond.

6.2. Newfoundland Power provides customers with appropriate options for reporting outages and restoration information.

Customers have call-in options during and after business hours and access to a Report Power Outage function through the website. Phone and website options also give customers access to restoration information. Customers can also report outages and obtain outage restoration using popular social media options.

6.3. Newfoundland Power appropriately responds to trouble calls.

Outage tickets are generated within the Outage Management System, which dispatches the outage tickets electronically to response crews. To facilitate faster response to trouble calls, trucks are equipped with transponders.

6.4. The Outage Management System has served adequately, but the Company is appropriately moving to a commercially provided replacement.

6.5. Outage cause coding supports Company needs.

6.6. The estimated restoration time process appears to have been reasonably effective, and should improve with the replacement of the existing SCADA system.

Newfoundland Power's communicates restoration times via its Informer application to its customers. Liberty cannot evaluate the accuracy of the estimated restoration times because Newfoundland Power does not document estimated restoration time accuracy data. It would appear likely, however, that the accuracy of estimated restoration times will improve substantially after Newfoundland Power has completed the replacement of its SCADA system with full distribution system coverage and with the replacement of its Outage Management System, both within five years.

E. Recommendations

Liberty has no recommendations in the area of outage management.

VII. Emergency Management

A. Background

Electric utilities should be well prepared to take actions necessary to minimize the effect on its customers for the occasional events that impact large numbers of customers and cause considerable system equipment damage. The elements required for effective customer restoration following the impact of a severe storm or other major event include being vigilant for approaching severe weather or power supply issues, having a formal emergency restoration organization with distinct duties and responsibilities, having a formal emergency response plan that defines all actions required to prepare for an event and all actions and communications required in response to the event, ensuring that sufficient employees and contractors are available on short notice, and providing all employees involved with an emergency event training in their duties through formal classes and "mock" drills. Liberty reviewed Newfoundland Power's Emergency Command Center, emergency management organization, staff emergency restoration training, tracking of approaching severe storms, emergency response plan and preparation checklist, and restoration performance following severe storms in the past.

B. Chapter Summary

Newfoundland Power's reasonable restoration times following past severe storm events indicate that its emergency management practices for severe storms are appropriate. The Company has a well-organized emergency management organization, it appropriately monitors the progress of approaching severe storms, it has a formal and appropriate storm restoration manual and a storm preparation checklist, it has sufficient resources to address large severe storms, and it conducts storm drills. The only concern Liberty observed is the need for the System Restoration Manual to address loss of supply issues and severe storm events.

C. Findings

1. Emergency Command Center

The System Control Center functions as the Emergency Command Center during major system events. [156] Newfoundland Power also has a fully functional backup control Center at a separate location. The System Control Center and backup link connect through a private fiber optic network that includes headquarters and substations in the St. John's area. This network provides redundant paths to ensure high availability of digital communications to field devices and voice communications with employees and customers.

System Operator workstations at the backup Center connect to the main or backup SCADA servers. Backup SCADA servers use data replicated on a real-time basis from the main SCADA servers. Operators also have access to all voice communications channels at the backup control Center.

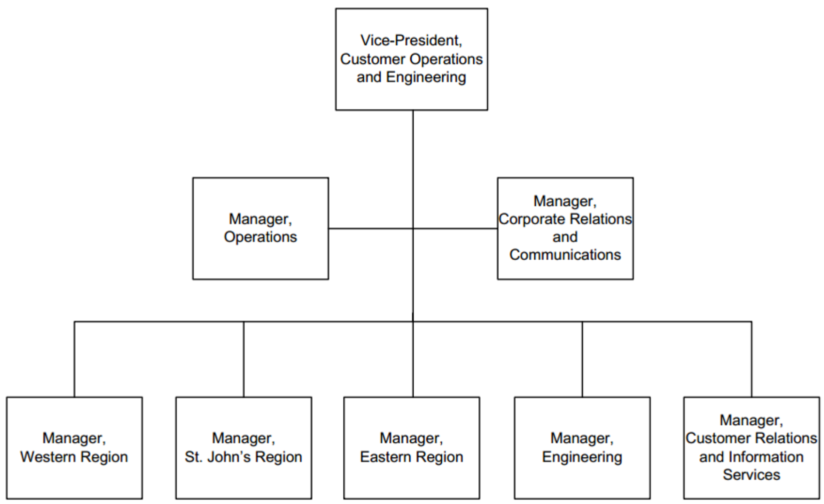
[156] Response to RFI #PUB-NP-028 and 186.

Newfoundland Power also uses its regional field operating Centers as emergency command Centers during more localized system events. During these events, the System Control Center transfers local control authority to regional staff. Newfoundland Power's technical and support staff gather in a central location in each regional Center that has the necessary computer and communications infrastructure to enable coordination of restoration efforts.

2. Emergency Management Staffing

Newfoundland Power[157] has a structured management control organization in place for emergency situations. The next chart illustrates this organization.

Chart 7.1: Newfoundland Power's Major Electrical System Event Organization Chart



The Vice-President of Customer Operations and Engineering has responsibility for preparing for and responding to major events. Managers responsible for electrical system operations, customer relations, and communications take lead roles in preparing and responding to major electrical system events. The Manager of Operations directs the System Control Center, Substation Operations, Generation Operations, Health and Safety, and Environment activities. This Manager also serves as Newfoundland Power's designate for communicating and coordinating electrical system issues with Hydro. When preparing for and responding to a major electrical system event, the Manager of Operations assumes a coordination role among managers responsible for the electrical system.

The three Regional Managers have responsibility for their region's transmission and distribution system field operations. These Regional Managers organize efforts to make repairs and restore service. When some regions suffer greater impact, Regional Managers may reassign personnel to assist with restoration efforts.

The Manager of Customer Relations and Information Services directs customer service efforts, and ensures effective operation of customer service telecommunications and internet based

[157] Response to RFI #PUB-NP-184.

systems. The Manager of Corporate Relations and Communications takes responsibility for communicating information to customers and stakeholders. This role includes issuing public advisories, posting messages on the Company's social media platforms, conducting media interviews, and interacting directly with stakeholders. These stakeholders include the Provincial Government, Fire and Emergency Services, and Hydro. During a major electrical system event, the Manager of Corporate Relations and Communications directs the Communications Hub.

Prior to a forecasted and during a major electrical system event,[158] senior management, led by the Vice-President of Customer Operations and Engineering, meets regularly to:

- Gauge the severity of the event
- Identify locations that require additional resources
- Determine need for deployment of mobile substations and generators
- Review restoration progress if major outages have occurred
- Determine communications requirements
- Discuss other matters that need immediate attention.

3. Personnel for Severe Storm Restoration

For a severe weather outage event, up to 432 of Newfoundland Power's[159] approximately 650 employees can be made available to assist emergency command management, and to conduct the restoration process. The Company can also call on local contractors[160] used for routine work as follows:

- Five who provide distribution construction services
- Three who provide transmission construction services
- Five who provide substation construction services
- Three who provide vegetation management services
- Three who provide poles and anchor installation services
- One who provides live line maintenance service (Avalon Peninsula only)
- One who provides streetlight installation and repair service
- Thirteen who provide civil works services.

Newfoundland Power[161] does not maintain any formal mutual aid agreements with other Canadian utilities because of the island's location and geographic features. The Company, however, has been working with other Canadian utilities via the Canadian Electricity Association to develop a nationwide standard agreement. Newfoundland Power and Hydro have access to each other's assistance. Newfoundland Power[162] also has access to resources from other Fortis-owned utilities, which travel time and logistics limit.

Staffing, especially skilled workers, comprises the most essential element in responding to widespread emergencies. On-island or neighboring contractors provide a source for

[158] Response to RFI #PUB-NP-184.
[159] Response to RFI #PUB-NP-152.
[160] Response to RFI #PUB-NP-195.
[161] Response to RFI #PUB-NP-183.
[162] Electric utilities across Canada, in New York State, and Grand Cayman Island.

supplementing skilled employees. During devastating events, such as Hurricane Igor, Newfoundland Power[163] had arranged for supplemental equipment from other utilities to be flown to the Island.

4. Emergency Restoration Training

Employee training includes training on the Company's service restoration, business continuity and disaster recovery plans.[164] Training includes major event drills on various events that may affect the system. Typically, such training includes a review of the applicable emergency response procedure or system restoration plan, involves a desktop review, and incorporates a partial or full drill exercise. Over the last five years, Newfoundland Power has conducted the following mock emergency drills, using specific system restoration plans:

- Loss of SCADA System
- Loss of System Control Center Building
- Loss of Switch and Outage Management Systems
- Loss of Generation Facilities
- Service Restoration Plan - Eastern Region
- Loss of Hydro Supply - Eastern Newfoundland
- Loss of Submarine Cables - Bell Island.

Actual events have provided a substantial source of experience since 2007:

- December 2007 winter storm in central Newfoundland
- March 2010 eastern Newfoundland sleet storm
- September 2010 Hurricane Igor
- December 2011 wind storm in western Newfoundland
- September 2012 Tropical Storm Leslie
- November 2013 snow storm in Central Newfoundland
- January 2013 loss of Hydro's transmission equipment
- January 2014 insufficient generation and loss of Hydro transmission equipment.

5. Emergency Response Enhancements

Newfoundland Power[165] has recently deployed mobile computing in all line trucks, implemented a computerized operations dispatch system, and expanded its use of geographic information systems in vehicles and for system assets. These changes enhance response capabilities for localized and widespread system distress. The Company also issued a System Restoration Manual in June, 2014. This manual updated action items required before, during, and after system emergencies, including equipment failures. The System Restoration Manual[166] supplements a Storm and Other Significant Event Preparation Checklist.

The System Restoration Manual does not include actions to address insufficient Hydro generation or loss of Hydro or Newfoundland Power transmission equipment. The manual does,

[163] On-site interviews, 19 September 2014.
[164] Response to RFI #PUB-NP-185.
[165] Response to RFI #PUB-NP-028.
[166] Response to RFI #PUB-NP-187.

however, included detailed procedures to prepare for severe storms and to conduct service restoration following storms. The manual's instructions address:

- Proactive monitoring approaching weather conditions
- Event preparations from the Storm and Other Significant Event Preparation Checklist
- Initial responses to system faults and restoration plans specific to the territory's five areas
- Air-patrol assessments to identify numbers and types of equipment damaged
- Actions to protect the public
- Actions to mitigate further damage (*e.g.*, potential cascading structure failures)
- Event categorization for use in determining restoration team requirements
- Restoration effects based on damage estimates including:
  - Detailed description of the damage
  - Time required to complete repairs
  - Materials required
  - Salvageable materials
  - The number of crews required
  - Specialized equipment requirements
  - Other resources required such as engineering, substations, and generation
- Restoration priorities
  - Importance of each line in the overall restoration process
  - Priority customers
  - Crew and material availability
  - Access to sites
- Establishing the Restoration Operations Center
- Communication with customers
- Determining workforce based on the level of the event
- Identifying and obtaining equipment and materials in excess of inventory
- Securing and dismantling damaged equipment
- Assignment of duties
- Rotating power outage and cold load pick up procedures
- Post-event and management reviews.

6. Severe Storm Tracking

Severe weather events generally affect only one particular area on the Island, but can affect the entire territory. Severe fall storms (when trees remain in leaf) typically involve tree contact. Winter and spring storms bring ice on lines and structures. Usually severe storms develop some distance from Newfoundland. The Company tracks them, and monitors their impact as they approach the Island. The Supervisor of System Control monitors weather alerts. Monitoring determines whether a forecasted storm has sufficient strength to cause likely damage. If so, the Manager of Operations begins preparation discussions with other operations management personnel, the Vice-President, and with Hydro to identify any shortfalls of generation and bulk power transmission anticipated.

Newfoundland Power[167]relies primarily on weather forecasts from Environment Canada. Newfoundland Power believes that the weather information from Environment Canada proves sufficient to plan adequately for weather events. Nevertheless, the Company has recently obtained forecasts from Provincial Aerospace,[168] which provides more detailed information. The Company may also seek information from the U.S. National Hurricane Center, where applicable.

Hydro subscribes to the LTRAX system, which monitors lightning strikes across North America; Newfoundland Power does not. Hydro alerts Newfoundland Power if it detects significant lightning approaching or already present. Newfoundland Power has also arranged for weather forecasts from Gander Airport. The Gander forecasts provide more detailed information than civilian sources. They are tailored for emergency responders.[169]

7. Storm Preparation Checklist

a. Prior to Severe Storm Arrival

Newfoundland Power typically[170] initiates severe storm response preparations for expected severe weather events two days prior to the event. For event threats posed by reduced bulk power generation or equipment issues, Newfoundland Power takes actions as soon as Hydro communicates the problem. The Company typically begins preparations for weather events under its Storm Preparation Checklist. This Checklist addresses:

- Preparing trucks, tools, materials, and generators (2.5 MW diesel and 6.5 MW gas turbine mobile generators and three portable substations, with a fourth imminently available)
- Verifying availability of off-road equipment and heavy equipment permits and escorts
- Coordinating response with Hydro and determining resources available from other utilities
- Holding pre-storm safety meetings
- Arranging accommodations
- Preparing generators at Company buildings
- Verifying Central Stores full staffing and sufficient stocks
- Deploying fueled mobile generators and portable substations
- Correcting any abnormal system configurations, changing protection settings, allowing equipment to operate under overloaded conditions
- Reviewing priority feeder and critical load lists
- Putting electrical, vegetation, flagging, snow clearing, and helicopter contractors on notice
- Preparing customer service and customer hub personnel
- Preparing Operations Center personnel and equipment
- Confirming accuracy with Department of Transportation and municipality contacts.

[167] Response to RFI #PUB-NP-028.
[168] Provincial Aerospace is a St. John's based defense contractor, specializing in airborne maritime surveillance.
[169] On site interviews, 19 September 2014.
[170] Response to RFI #PUB-NP-028.

Regional Operations staffs are place on alert two days prior to anticipated severe weather events. Where practical, equipment subject to work in progress and temporary system conditions is returned to service and to normal configuration. Staffing numbers and optimum location undergo review. If necessary, employees are recalled from vacation and other employees, trained in duties to support the regular workforce, are put on notice. Contractors are put on notice and contact is made with other utilities to determine if those resources are available, if needed.

On the day before the severe storm, Newfoundland Power continues preparations started on the day before, and deploys resources to locations where severe storm damage is most likely. Employees are briefed on anticipated work conditions and when and where they are expected to report for work. The Company contacts key customers -- government, municipalities, schools and hospitals, to ensure that they are making necessary preparations for the upcoming event.

b. The Day of Arrival

On the day of the event, the System Control Center monitors the system, and notifies the regional field operations and the customer service staff of equipment failures as they occur. The Customer Contact Center also keeps operations staff up to date on outages reported by customer calls.

Experienced, line crews or technical staff are dispatched to assess damage failures. Based on priority, the appropriate work crews are dispatched to facilitate repairs. The highest priority repairs involve removing hazards to the public, and repairing transmission lines, substations, and mainline feeders. Repair work orders go into a dispatch queue, for the next available crew. As needed, the Company deploys engineering and information services staff, and other personnel with operations experience to the System Control Center, Customer Contact Center, and Regional Operations facilities to provide on-site support for critical technology and to supplement the regular complement of employees.

8. Coordination with Hydro

Newfoundland Power's[171] System Control Center and Hydro's Energy Control Center coordinate restoration efforts following major system events. When responding to major electrical system events, Newfoundland Power's System Control Center and Hydro's Energy Control Center work together to reestablish normal operations on the electrical system in a controlled and orderly fashion. Newfoundland Power's Control Center relies upon Hydro's Energy Control Center to keep it updated on system demand. Similarly, Newfoundland Power's Control Center relies upon its Hydro counterpart for information concerning availability of Hydro's generation resources.

9. Service Restoration Times

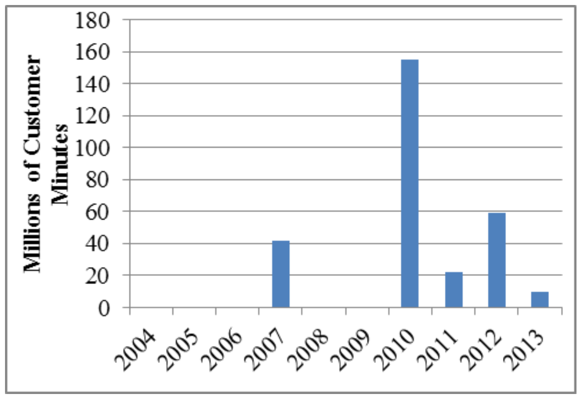
The amount of time to restore customers following a severe impact storm depends on a number of variables. These variables include storm type (heavy snow, wind, ice, or flooding), the type and amount of equipment damaged, the amount of the system affected, and travel restrictions caused by factors such as downed trees and snow coverings on roads. A review of restoration times following severe storms provides one indication of effectiveness in storm restoration activities.

[171] Response to RFI #PUB-NP-002.

a. December 2007 Wet Snow and Ice Storm

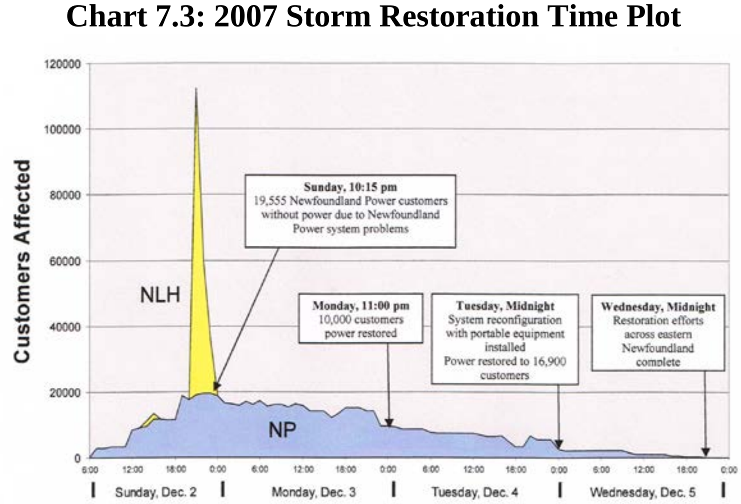
Prior to the 2013 and 2014 events, Newfoundland Power[172] had experienced several severe storms and other events that affected substantial numbers of its customers. The next chart shows the minutes of customer interruptions (in millions) for the severe storm-caused events affecting Newfoundland customers during since 2004.

Chart 7.2: Significant Storm-Caused Outages



In December of 2007 Newfoundland Power[173] faced a wet snow and ice storm with winds gusts of up to 160 kilometers per hour and ice loads of as much as 1.5 inches. During the storm, a problem on Hydro's electrical system resulted in a power interruption of up to 2.5 hours for 93,000 customers in the greater St. John's area. Damage to the Newfoundland Power system affected over 19,500 customers (about 8 percent), many for several days. Newfoundland Power spent about $1.7 million restoring customers and replacing damaged equipment. About 200 Newfoundland Power employees were involved in the restoration process, as well as Hydro and contractor personnel. The next chart shows the restoration time plot for the December 2007 storm.

Chart 7.3: 2007 Storm Restoration Time Plot



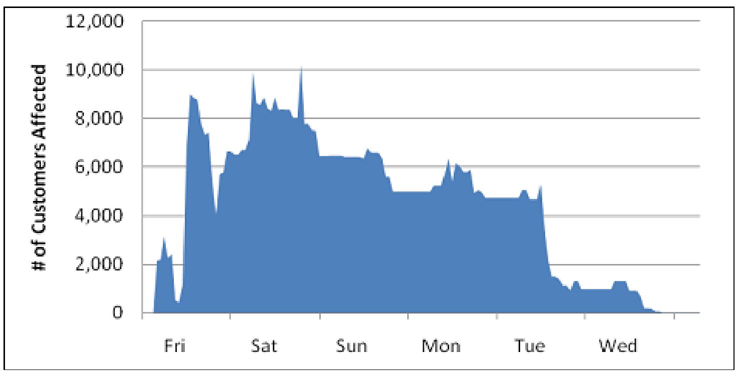
[172] Newfoundland Power graphic presentation on February 12, 2014.
[173] Response to RFI #PUB-NP-189.

b. March 2010 Ice Storm

Newfoundland Power suffered[174] two major storms in 2010. A March 2010 ice storm affected portions of the Avalon Peninsula, with actual ice loads in excess of 1.5 inches of radial ice. The resulting line and structure damage affected about 12,500 customers. Average time to restore customers, due to the extent of the damage, was about 58 hours. The storm caused over 43 million minutes of customer interruption time. This was the exception to the average customer minutes of interruption experienced during the other major events. Although the number of customers impacted by the storm was relatively small (about 5 percent of all customers) Newfoundland Power spent about $4.2 million for restoring customers and replacing damaged equipment.

The next chart shows the restoration time plot for the March 2010 ice storm.

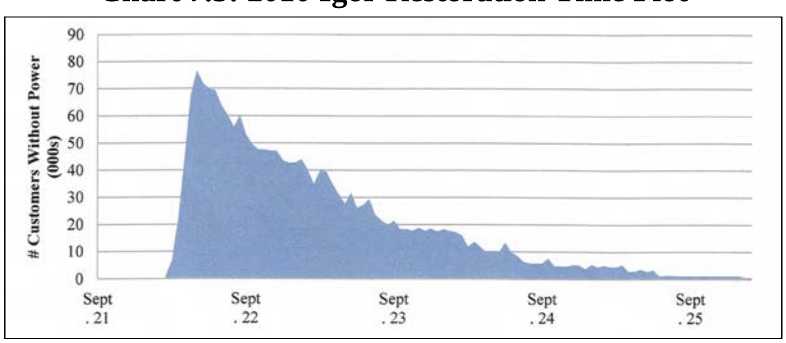
Chart 7.4: 2010 Ice Storm Restoration Time Plot



c. September 2010 Hurricane Igor

Hurricane Igor caused extensive flooding and high winds on September 22, 2010. Customers experienced, on average, about 17.5 hours of interruptions. About 106,000 customers (about 40 percent of total customers) were impacted by the storm. Newfoundland Power restored the bulk of its affected customers within three days. The storm caused 111 million minutes of customer interruption time. The Company spent about $1.9 million restoring customers and replacing damaged equipment. The next chart shows the restoration time plot for Hurricane Igor.

Chart 7.5: 2010 Igor Restoration Time Plot



[174] Response to RFI #PUB-NP-189.

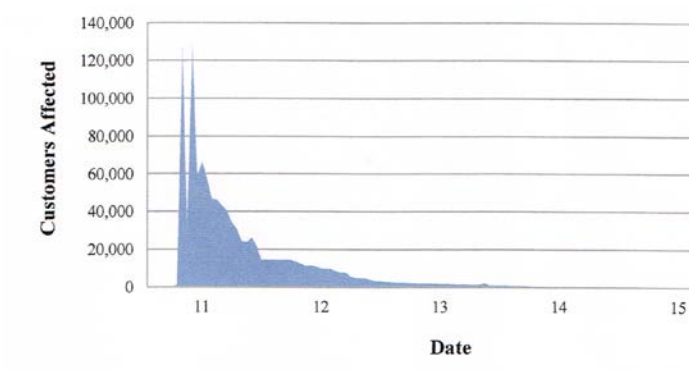
d. December 2011 Wind Storm

A wind storm struck in December 2011,[175] bringing high winds and affecting about 16,000 customers (about 6 percent of total customers) in remote areas. Average interruptions lasted about nine hours. Newfoundland Power restored all customers impacted within two days.

e. September 2012 Tropical Storm Leslie

Tropical Storm Leslie[176] in September of 2012, caused the loss of about 128,700 customers (about 49 percent), with an average duration of about 7½ hours. Newfoundland Power deployed 255 personnel to restore services. The bulk of customers were restored within two days. Newfoundland Power spent about $635,000 to replace damaged equipment. Chart 7.6, below, indicates the Newfoundland Power's restoration time plot for Tropical Storm Leslie in September 2012.

Chart 7.6: 2012 Storm Leslie Restoration Time Plot



f. The Hydro Terminal Station/Transmission Event in January 2013

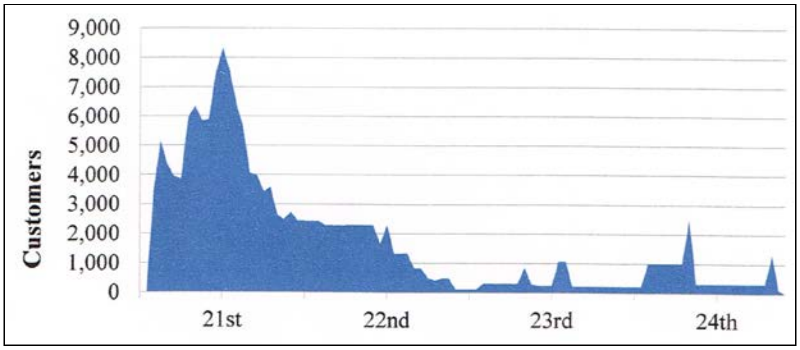
In January 2013, Hydro equipment problems, both generation and terminal stations, caused the loss of load for 173,000 Newfoundland Power customers with an average duration of over 11 hours.

g. The November 2013 Winter Storm

In November, 2013[177] a Winter Storm caused the loss of about 12,000 customers for an average duration of 9 hours. The bulk of the customers were restored within two days. The next chart shows the restoration time plot for November 2013 storm.

175 Response to RFI #PUB-NP-166.
176 Response to RFI #PUB-NP-166.
177 Response to RFI #PUB-NP-166.

Chart 7.7: 2013 Storm Restoration Time Plot



h. The January 2014 Events

Insufficient generation capacity and terminal station equipment failures on Hydro's system in January 2014 caused the loss of load to about 188,000 customers, with an average duration of about 12½ hours. This event affected more Newfoundland Power customers than any of the severe storms affecting Newfoundland Power's customers since 2007.

D. Conclusions

7.1. Newfoundland Power's emergency response practices are effective and consistent with good utility practices.

Newfoundland Power was able to restore the bulk of the customers affected by its two largest recent storm events (Hurricane Igor and Tropical Storm Leslie) within two or three days. The only storm resulting in lengthy restoration time was the 2010 ice storm, which produced extensive damage to some transmission lines and distribution feeders. That storm, however, only affected about 5 percent of Newfoundland Power's customers.

Newfoundland Power's response times to severe storms should improve via increased restoration efficiencies, following installation of its new Outage Management and SCADA systems. The additional downstream feeder reclosers being installed by Newfoundland Power on some of its distribution feeders will also assist in storm restorations by helping to isolate faults and by mitigating the cold load pick up effects.

7.2. Newfoundland Power has made effective pre-assignment of management and operational duties for its emergency management organization.

Newfoundland Power's emergency management organization has well-defined control and command duties and responsibilities. Newfoundland Power has a large number of employees available and trained for addressing or assisting with the preparation of a forecasted severe storm event and for assigning specific storm duties. It also has local contractors available to assist.

7.3. Newfoundland Power's Emergency Command Center has appropriate capability and functionality.

The Company has dedicated a room located in its System Control Center as its Emergency Command Center, and equipped it with SCADA monitoring capability. The[178] System Control Center functions as its Emergency Command Center during major system events across its service territory.

7.4. Newfoundland Power has a well-defined process for tracking severe storms.

Newfoundland Power is vigilant in monitoring approaching weather that might produce severe storms for the island and it triggers its storm preparation checklist two days before a severe storm is anticipated to affect the Island. Newfoundland Power appropriately tracks approaching storms, and uses weather data from an appropriate number and range of services.

7.5. Newfoundland Power has a range of in-house and contractor resources for timely restoration of even large severe weather events.

For a severe weather outage event, up to 432 of Newfoundland Power's approximately 650 employees can be made available to assist emergency command management and to conduct the restoration process. Newfoundland Power also has access to numerous contractors and Hydro personnel, if needed.

7.6. Newfoundland Power conducts training exercises for its emergency management personnel.

Newfoundland Power has conducted mock emergency drills seven times over the last five years.

7.7. Newfoundland Power's formal System Restoration Manual is consistent with good utility practice, except that it does not describe actions for insufficient generation. (*Recommendation #7.1*)

With only one exception, Liberty found the considerations and procedures described in the restoration manual thorough and appropriate, and consistent with good utility practices. Newfoundland Power has separate procedures for conducting rotating power outages and for mitigating cold load pick up issues when restoring distribution feeders. The System Restoration Manual, however, does not formally describe communications and operating considerations and actions, including reducing system voltage, providing additional generation, and conducting rotating feeder outages if and when Hydro is unable to supply peak demand.

7.8. Newfoundland Power and Hydro cooperate in severe storm restoration efforts.

Newfoundland Power's System Control Center and Hydro's Energy Control Center coordinate restoration efforts following major system events caused by severe storm-caused equipment damage, and by the failure of major system components or the loss of supply. When responding to major electrical system events, Newfoundland Power's System Control Center and Hydro's Energy Control Center work together to reestablish normal operations on the electrical system in a controlled and orderly fashion.

[178] Responses to RFIs #PUB-NP-028 and 186.

E. Recommendations

7.1. Include in the System Restoration Manual a section delineating actions for the loss of supply to its system, such as occurred in January 2014. (*Conclusion #7.7*)

VIII. Customer Service and Outage Communications

A. Background

Liberty performed a review of Newfoundland Power's progress addressing outage communications recommendations arising from Liberty's April 24, 2014 Interim Report. Liberty's Interim Report contained eight recommendations that jointly concern Newfoundland Power and Hydro, one specific to Newfoundland Power, and one specific to Hydro. Newfoundland Power has undertaken initiatives to improve outage communications and inter-utility coordination in response to the nine recommendations that concern it. Newfoundland Power reports that actions to address seven of the nine recommendations initiatives have been completed. It plans to complete the remaining two initiatives by the end of 2014.

#	Recommendation	Status
37	Develop Joint Outage Communications Technology Strategy	Complete
38	Conduct Joint Customer Outage Expectations Research	Complete
39	Stress Test Enhancements to Customer-Facing Technologies	Complete
41	Pursue Multi-Channel Communications	In Progress
42	Develop Advance Notification Communications Protocols	Complete
43	Improve Conservation Request Communications	In Progress
44	Develop Storm/Outage Communications Plan	Complete
45	Conduct a Joint Lessons-Learned Exercise	Complete
46	Create Executive-Level Committee to Guide Initiatives	Complete

B. Chapter Summary

This chapter reviews Newfoundland Power's reported progress in addressing recommendations to improve outage communications. In the days since the January outage event, Newfoundland Power and Hydro have worked individually and jointly to tackle outage communications issues and improve inter-utility coordination.

A joint executive-level committee directed efforts and facilitated joint cooperation in resolving issues, including the creation of an advance notification protocol to guide decisions and communications during times of reduced generation reserves. Newfoundland Power and Hydro also conducted a joint lessons learned session to discuss opportunities to improve inter-utility coordination and communications. A Joint Communications Plan was created to encourage coordinated and consistent communications during anticipated or actual outage events and both utilities tested the new plan through a joint supply shortage tabletop exercise. Newfoundland Power's website and call handling technologies were expanded and stress-tested to confirm proper operation and responsiveness.

Newfoundland Power has made significant progress on the outage improvement recommendations, completing seven of nine recommendations, but two important recommendations remain. While Newfoundland Power has targeted a year-end date to complete the implementation of the two remaining issues, work will likely continue through the winter to support these initiatives.

Jointly-conducted customer research identified a need for customer education to highlight ways to conserve electricity and to help customers and the public understand the impact of conservation on the IIS. As a result, Newfoundland Power has created a customer education and awareness plan and scheduled customer outreach to raise conservation awareness. This effort will continue throughout the winter.

Newfoundland Power is also in the middle of a technology implementation that will introduce a "texting" option for customers who prefer to receive notifications by text message. Newfoundland Power reports that this feature will be rolled out to customers by December 31, 2014. However, more work will be required over the coming months to promote the option to customers. Newfoundland Power should take steps to measure and monitor the customer experience of this new customer-facing technology and communications tool to ensure a good customer experience.

The next sections address the status of actions responding to each recommendation.

C. Findings

1. Join Outage Communications Technology Strategy

Liberty's recommendation stated:

> *As a first step, Newfoundland Power and Hydro should develop an Outage Communications Strategy to prioritize opportunities and guide near- and longer-term improvements to customer contact technologies and telephony, beginning with preparation by June 15, 2014 of a detailed plan and schedule for doing so.*

In June, Newfoundland Power developed an outage communications strategy to guide near- and long-term improvements to outage technologies. Near-term initiatives remain underway to address recommendations described in this section (SMS, stress testing, website capacity). Longer-term plans include full deployment of GIS, replacement of SCADA, enhancing website to enable responsive design (all devices), replacement of the Outage Management System, and high-volume third-party overflow IVR services.

Hydro finalized a Customer Service Strategic Roadmap[179] in September. This document describes plans to enhance and improve customer service related technologies over the next three years. Near-term initiatives include revising outage protocols and formalizing after-hours telephone support. In addition, Newfoundland Power and Hydro have discussed possible synergies for shared customer contact and outage communications technologies, especially as Hydro faces replacement of its customer information system, revisions to its customer service pages on its website, and upgrades to its call center telephony over the next few years.

Work to address this recommendation has been reported as completed.

[179] Response to RFI #PUB-NLH-202.

2. Joint Customer Outage Expectations Research

Liberty's recommendation stated:

> *Hydro and Newfoundland Power should conduct customer research (primarily on a joint basis), in order better to understand customer outage-related informational needs and expectations, including requests for conservation, and incorporate results into the Outage Communications Strategies, beginning with preparation by June 15, 2014 of a detailed plan and schedule for doing so.*

Hydro and Newfoundland Power jointly conducted customer research over the summer to understand customer expectations regarding outage-related communications. They conducted a number of surveys:

- Telephone survey of 800 residential customers
- Focus groups to explore preferences in St John's, Carbonear/Sunnyside, Central Newfoundland, and Rocky Harbor
- Online survey of 100+ business customers

Results from this customer research highlighted the need to provide increased education on the ways customers can conserve, including businesses. Additionally, customers shared expectations on how soon ETRs should be provided, how often they should be updated, and how much time is needed to prepare for a potential outage event. This information has been used to revise outage communications and storm preparation protocols.

Work to address this recommendation has been reported as completed.

3. Stress Testing Technology Enhancements

Liberty's recommendation stated:

> *As Newfoundland Power and Hydro move forward with enhancements to any customer-facing outage support systems, each should stress test the technologies well prior to the winter season; this element should comprise a key component of their implementation processes.*

Newfoundland Power conducted extensive stress testing of its website and contact center telephony over the summer. As a result of these efforts, Newfoundland Power's website has been fortified and stress tested, and its contact center telephony has been expanded and stress tested.

Newfoundland Power conducted a series of stress tests of the responsiveness and reliability of the website outage pages. The stress tests replicated the volume of website activity experienced during the January outage event. The testing confirmed capacity requirements and identified slower performing applications. At the same time, the testing vendor provided recommendations to optimize website coding and integration to improve the speed and reliability of the website. Newfoundland Power has secured a means to dynamically boost the capacity of its webservers should demand increase in the future. Additionally, Newfoundland Power continues to contract with a vendor to monitor website performance on an ongoing basis.

Newfoundland Power contracted with another vendor to conduct stress testing of its current telephony configuration. A series of tests were conducted over the summer to simulate the volume of calls received during the January event. The initial test identified an issue with the configuration that has subsequently been resolved and retested. Additionally, Newfoundland Power stress tested the T1 trunk that was added following the January outage. Newfoundland Power will test additions or changes to the telephony going forward.

Work to address this recommendation has been reported as completed. Future monitoring and testing will continue as required.

4. Multi-Channel Communications

Liberty's recommendation stated:

> *Newfoundland Power and Hydro should pursue (primarily on a joint basis) other multi-channel communication options, such as two-way SMS Text messaging or Broadcasting options, for delivering Outage Status Updates, beginning with preparation by June 15, 2014 of a detailed plan and schedule for doing so.*

Newfoundland Power has selected a vendor to proceed with an enhancement that will provide multi-channel communications options for customers. This enhancement will enable Newfoundland Power to communicate with customers in the manner they select, whether by phone, email, or SMS texting. Customers will be able to indicate communications preferences through Newfoundland Power's website, including specifying the best available contact phone number or email address. The solution will work in conjunction with Newfoundland Power's existing "Communications HUB" process to enable multi-channel communication of outage and storm information to customers.

The project is currently on on-track. Newfoundland Power introduced the service to its employees on December 1, 2014. Employees will be testing the product to ensure proper operation. Following a successful employee-test, Newfoundland Power will roll out this service option to customers.

5. Advance Notification Communications Protocols

Liberty's recommendation stated:

> *Newfoundland Power and Hydro should aggressively pursue a joint process for delivering advance notification for planned rotating outages, in order to facilitate good initial communications with customers during an outage event, beginning with preparation by June 15, 2014 of a detailed plan and schedule for doing so.*

Newfoundland Power and Hydro have jointly developed an advance notification protocol to guide customer communications when generation reserve margins are expected to dip below predetermined thresholds. Hydro modified its T001 protocol to project a shortfall in generation reserves in stages of severity:

- 0-Normal (5-day forecast greater than largest generating unit plus minimum spinning reserves)

- 1-Power Advisory (5-day forecast less than largest generating unit plus minimum spinning)
- 2-Power Watch (24-hour forecast indicates reserves less than largest generating unit)
- 3-Power Warning (Current day reserve margin is less than half of the largest generating unit)
- 4-Power Emergency (Generation shortfall imminent, no reserve margin).

Stakeholders will be notified based on the forecasted severity. Customer notifications guidelines have been established to guide the release of public information for each stage and determines the point at which customers will be asked to conserve electricity and when advisories should be issued to prepare customers for rotating power outages, should they be required.

Work to address this recommendation has been reported as completed.

6. Conservation Request Communications

Liberty's recommendation stated:

> *Newfoundland Power should implement goals to communicate better with stakeholders in the aftermath of outages. If conservation requests have been made of the public, Newfoundland Power should provide feedback following the event to indicate the amount of conservation achieved, and encourage future conservation, beginning with preparation by June 15, 2014 of a detailed plan and schedule for doing so.*

Customer research conducted this summer highlighted the need to provide additional customer education around conservation requests, such as the one issued during the January 2014 event. Residential and business customers indicated that they needed more advance warning to prepare for conservation requests. Focus group research revealed that customers might be using more power after the request to conserve, in order to prepare for the impending outage (*e.g.*, turning up the heat, doing laundry, cooking meals). In addition, customer education is needed to help customers prioritize their efforts to conserve.

To address these issues, Newfoundland Power and Hydro have developed a coordinated customer education and awareness plan. Company website and social media pages have been updated to explain the new advance notification protocol, to demonstrate ways to conserve, and to explain why conservation is important for the IIS. This same message is being shared with media outlets and in public speaking engagements to encourage winter preparedness and emphasize the importance of conservation. December customer bills will also contain an insert communicating this information.

Newfoundland Power and Hydro are not technically able to measure the actual amount of electricity that customers conserve after a conservation request. Instead, following a conservation request, the utilities will provide general feedback such that customers can understand the impact of conservation efforts in terms of reduced or avoided rotating outages. This feedback will provide another opportunity for the utilities to reiterate the importance of conservation and the best ways to conserve, to continue the dialogue.

Additionally, Newfoundland Power is actively partnering with local business organizations to discuss conservation options with businesses and to encourage future cooperation.

Both utilities have updated their critical infrastructure and customer lists. Newfoundland Power is actively meeting with large commercial customers to discuss conservation requests, outage communications, and when possible, to participate in regional emergency response drills.

Newfoundland Power and Hydro have also developed a Joint Communications Plan to guide customer communications during large outages or events. This plan is described in the following recommendation.

Actions to address this recommendation are still underway. Customer outreach will continue throughout the winter as needed. Feedback will be provided, as required, following any future conservation requests.

7. Storm/Outage Communications Plan

Liberty's recommendation stated:

> *Hydro and Newfoundland Power should jointly develop a coordinated, robust, well-tested and up-to-date Storm/Outage Communications Plan documenting protocols, plans, and templates to guide communications during major events, beginning with preparation by June 15, 2014 of a detailed plan and schedule for doing so.*

Newfoundland Power and Hydro have developed a Joint Communications Plan[180] to guide customer communications during large outages or events. The Joint Outage Communications Plan provides clear guidelines and templates for major events that result in damage to or interruption of power supply to the island interconnected electricity system. The Plan is intended to ensure that the Utilities are the primary authoritative voice during a critical incident that affects either Company's operations. It enables both Corporate Communications Teams to quickly activate, and provides strategies, tools and templates to effectively communicate to customers, employees, media and key stakeholders during outage situations.

The plan was successfully tested through a tabletop scenario drill in September 2014. Individuals representing operations, management, and communications from both utilities were involved in the testing exercise. The test of the Plan was successful—both utilities were prepared to handle the scenario and the Plan guided communications at all levels[181]. The Joint Communications Plan will be updated as needed to capture any changes to the process, including any lessons learned from future outages or storms. Additionally, Hydro and Newfoundland Power have committed to testing the plan annually.

Work to address this recommendation has been reported as completed.

[180] PUB-NLH-304 Attachment 1
[181] PUB-NLH-460 Attachment 1

8. Joint Lessons-Learned Exercise

Liberty's recommendation stated:

> *Newfoundland Power and Hydro should conduct a joint "lessons learned" exercise including both their Communications Teams, beginning with preparation by June 15, 2014 of a detailed plan and schedule for doing so.*

The Communications Teams from Hydro and Newfoundland Power conducted a joint "lessons learned" session on May 20, 2014 to review the January outage event. The joint session was broadened to include individuals from customer service, operations, and energy efficiency. Discussions covered the January events as well as initiatives underway following the event. Discussion focused on ways to work jointly to address issues, ways to share information, planned improvement initiatives, and customer research.

Both utilities plan to conduct similar joint lessons-learned sessions following any future events.

Work to address this recommendation has been reported as completed.

9. Executive-Level Committee to Guide Initiatives

Liberty's recommendation stated:

> *Hydro and Newfoundland Power should commit to a formal effort, sponsored at their most senior executive levels, to work together in formulating joint efforts to identify goals, protocols, programs, and activities that will improve operational and customer information and communications coordination, leading to the development, by June 15, 2014, of identified membership on joint teams, operating under senior executive direction and according to clear objectives, plans, and schedules.*

An executive-level committee of senior managers from both utilities was given an enhanced focus following Liberty's 2014 Interim Report. Since April, this committee has been meeting monthly to oversee joint recommendations, discuss action items, and coordinate activities.

A key accomplishment of the executive committee was the joint development of the Customer and Stakeholder Advance Notification Protocol (refer to recommendation #42 in Liberty's Interim Report). These meetings were used to further the discussions around stakeholder information needs as well as the thresholds guiding the release of information. These discussions established the foundation for the Joint Communications Plan (refer to recommendation #44 in Liberty's Interim Report).

This committee was also key in expanding the level of real-time status information available between Hydro and Newfoundland Power concerning the status of lines, equipment, and generation. Additionally, short-term load and generation information is being made accessible to Newfoundland Power, which will determine the timing of customer communications during a projected shortfall.

Subsequent meetings defined the need to jointly test the advance communications protocols and the Joint Communications Plan. A successful tabletop drill was ultimately conducted in late October.

This committee also served as a forum to discuss ways to improve operational coordination as well as discuss progress on other joint recommendations, including the customer research, multi-channel outage communications, and technology stress testing. While many of the action items subsequently have been completed, these meetings continue on a monthly basis to address any issues requiring inter-utility cooperation.

Work to address this recommendation has been reported as completed.

D. Conclusions

8.1. Newfoundland Power has made significant progress on the outage improvement recommendations, but important monitoring work remains. (*Recommendation #8.1*)

One of Liberty's recommendations in its Interim Report (*Item #41*) involved the implementation of new customer-facing technologies to enable multi-channel communications with customers. The implementation for this recommendation is still underway. As with the introduction of any new customer-facing technology, it is important to monitor the customer experience to ensure the service is working as intended and to provide feedback to improve the service if necessary.

E. Recommendations

8.1 Monitor the "customer experience" of the new multi-channel communications services, and adjust the service offering as necessary to ensure a good customer experience. *(Conclusion #8.1)*

Newfoundland Power's effort to introduce multi-channel communications is just beginning with the implementation of the SMS iFactor solution on Newfoundland Power's website. More work will be required over the coming months to introduce and promote the technology to customers and to gather customer feedback. Implementation progress should be monitored. Additionally, Newfoundland Power should take steps to measure the customer experience of this new customer-facing technology and communications tool.

Appendix A: Conclusions and Recommendations Summary

Chapter II: Planning and Design

Conclusions

2.1. T&D reliability has substantially improved since 1999 and has recently remained stable overall.

2.2. The large contribution that the distribution system makes to outages and the number of equipment-caused failures indicate room for further improvement in reliability. (*Recommendation #2.1*)

2.3. Newfoundland Power focused on worst performing feeders for some time, but has recently ceased committing resources to them despite the fact that such feeders still exhibit disproportionately high outage metrics. *(Recommendation #2.2)*

2.4. Newfoundland Power's Transmission and distribution systems operate effectively in ensuring adequate service reliability.

2.5. The expanded work of the Inter-Utility System Planning and Reliability Committee commenced in 2014 should improve planning coordination between Newfoundland Power and Hydro.

2.6. Capital programs have been effective in improving reliability, but better methods for prioritizing projects under consideration exist. *(Recommendation # 2.3)*

2.7. Newfoundland Power has incorporated appropriate levels of redundancy in its transmission and distribution systems and in its substations.

2.8. Newfoundland Power employs appropriate design standards, criteria, and practices for transmission and distribution lines.

2.9. Current use of SCADA and use of automatic reclosers on feeders downstream from substations currently do not serve to minimize interruption frequency and duration. *(Recommendation # 2.4)*

2.10. Newfoundland Power employs appropriate lightning and animal protection.

2.11. Newfoundland Power makes effective use of short circuit studies.

2.12. Completion of in-process developments in the Geographic Information System will increase its effectiveness.

2.13. Newfoundland Power's protective relay schemes conform to industry practice, but they do not operate under documented guidance. *(Recommendation #2.5)*

2.14. A temporary delay in testing of electromechanical relays is being addressed.

2.15. Newfoundland Power does not formally periodically exercise its circuit breakers. *(Recommendation #2.6)*

2.16. Newfoundland Power does not centrally track actions to address the causes of frequent protective device operations. *(Recommendation #2.7)*

Recommendations

2.1. Increase the emphasis on the Rebuild Distribution Lines initiative in annual capital budgets, with the goal of reducing distribution equipment failures. *(Conclusion #2.2)*

2.2. Perform a structured evaluation of the costs and benefits of reinstituting a regular annual program for addressing worst performing feeders. *(Conclusion #2.3)*

2.3. Develop a weighted analytical scoring of criteria process to support capital planning; include in this a scoring criterion that relates expected project costs to avoided numbers of customer interruptions or minutes. *(Conclusion #2.6)*

2.4. Investigate the installation of downstream feeder reclosers for the purpose of improving distribution SAIFI and SAIDI indices, in addition for reducing cold load pick up difficulties, with priorities given to feeders based on installation costs versus anticipated avoided customer interruptions. *(Conclusion # 2.9)*

2.5. Document protective relay scheme objectives, criteria, and methods for protecting transmission lines, buses, and distribution feeders. *(Conclusion #2.13)*

2.6. Conduct circuit breaker operation tests from relays (so called trip checking) on a periodic basis to assure that all relay trip circuits and circuit breakers operate as intended. *(Conclusion #2.15)*

2.7. Centrally report multiple device operations. *(Conclusion #2.16)*

Chapter III: Asset Management

Conclusions

3.1. Asset management at Newfoundland Power operates: (a) under a program, (b) with an organization, and (c) with the support of sufficient numbers and skills to meet system reliability needs effectively.

3.2. Newfoundland Power uses an effective combination of periodic O&M inspection and maintenance programs and capital transmission, distribution, and annual capital substation capital rebuild and modernization projects to address condition, reliability, and operating issues with its transmission, distribution, and substation assets.

3.3. Newfoundland Power completes its transmission, substation, and distribution inspection and maintenance work in a reasonably timely fashion.

3.4. Newfoundland Power's transmission line and pole inspection and corrective maintenance practices are consistent with good utility practices, except that the Company does not have a program to chemically treat its aged poles. *(Recommendation #3.1)*

3.5. Newfoundland Power's distribution feeder and pole inspections and corrective maintenance practices are generally consistent with good utility practices, except for: (a) lack of periodic sounding (testing for internal decay) of all aged poles, and (b) a slow replacement rate for aged distribution poles. *(Recommendation #3.2)*

3.6. Newfoundland Power's substation inspection, corrective maintenance, and preventive maintenance practices are consistent with good utility practices.

3.7. Newfoundland Power's vegetation management practices are consistent with good utility practices.

3.8. Newfoundland Power's T&D System Rebuild and Modernizations Strategies are generally consistent with system needs.

3.9 As indicated in Chapter II, despite notable reliability improvement since 1999 and stable SAIFI and SAIDI metrics exhibited recently, it appears that room remains for improving distribution equipment-caused customer interruptions by applying more weight to the Rebuild Distribution Lines Project. *(Recommendation #2.1)*

Recommendations

3.1. Unless it can show that fungus and insect infestation does not occur on its wood poles, Newfoundland Power should reconsider the need to treat its transmission poles for fungus and insect infestation, as does Hydro. *(Conclusion #3.4)*

3.2. Consider conducting "sounding" tests on all older distribution poles (not just those obviously rotted) when inspecting feeders; reconsider chemically treating distribution poles to extend their lives. *(Conclusion #3.5)*

Chapter IV: Power Systems Operations

Conclusions

4.1. The System Control Center is appropriately equipped and backed up by two other locations.

4.2. Although the SCC has a control console used for one-on-one training, it does not have software for simulating the electric systems under normal and emergency conditions. (*Recommendation #4.1*)

4.3. Newfoundland Power's use of its Central Dispatch Team to relieve the System Control Center of duties for managing and dispatching planned work and trouble call crews during regular hours and emergencies is a sound practice.

4.4. The System Control Center and the Central Dispatch Team are appropriately staffed.

4.5. Newfoundland Power appropriately monitors its transmission system, its infeed points from Hydro, and Hydro's generation via a link between Hydro's Energy Management System and Newfoundland Power's SCADA system.

4.6. The planned replacement of Newfoundland Power's SCADA system and its Outage Management System should improve the effectiveness of its system operations.

4.7. The System Control Center and the Central Dispatch Team appropriately use software tools for managing system operations.

4.8. Newfoundland Power's SCC does not have an Energy Management System because it links its SCADA system to Hydro's EMS.

4.9. The System Control Center does not have an operations software tool for producing daily forecasts. (*Recommendation #4.2*)

4.10. If Hydro had timely consulted with Newfoundland Power about solutions for mitigating Hydro's generation shortfalls, Newfoundland Power would possibly have been better able to mitigate the issue with voltage reductions and load curtailments.

Recommendations

4.1. Include in the specification for the new SCADA system the ability to turn an operator console into a formal training system simulation console for instruction and evaluation. (*Conclusion #4.2*)

4.2. Consider including a short-term forecasting application, if possible, when it replaces its current SCADA system. (*Conclusion #4.9*)

Chapter V: Generation

Conclusions

5.1. Newfoundland Power has appropriately operated and maintained its generating units.

5.2. Newfoundland Power has maintained a reasonable level of generating availability.

5.3. Newfoundland Power has analyzed and is addressing issues, such as water and fuel supply, that may enhance the capacity it can make available to the Island Interconnected System during periods of generation shortage.

5.4. Newfoundland Power can control its larger units through SCADA or other automatic means.

Recommendations

Liberty has no recommendations related to Newfoundland Power generation.

Chapter VI: Outage Management

Conclusions

6.1. The numbers and locations of field personnel assigned to outage response duties are appropriate in meeting outage-related needs.

6.2. Newfoundland Power provides customers with appropriate options for reporting outages and restoration information.

6.3. Newfoundland Power appropriately responds to trouble calls.

6.4. The Outage Management System has served adequately, but the Company is appropriately moving to a commercially provided replacement.

6.5. Outage cause coding supports Company needs.

6.6. The estimated restoration time process appears to have been reasonably effective, and should improve with the replacement of the existing SCADA system.

Recommendations

Liberty has no recommendations in the area of outage management.

Chapter VII: Emergency Management

Conclusions

7.1. Newfoundland Power's emergency response practices are effective and consistent with good utility practices.

7.2. Newfoundland Power has made effective pre-assignment of management and operational duties for its emergency management organization.

7.3. Newfoundland Power's Emergency Command Center has appropriate capability and functionality.

7.4. Newfoundland Power has a well-defined process for tracking severe storms.

7.5. Newfoundland Power has a range of in-house and contractor resources for timely restoration of even large severe weather events.

7.6. Newfoundland Power conducts training exercises for its emergency management personnel.

7.7. Newfoundland Power's formal System Restoration Manual is consistent with good utility practice, except that it does not describe actions for insufficient generation. (*Recommendation #7.1*)

7.8. Newfoundland Power and Hydro cooperate in severe storm restoration efforts.

Recommendations

7.1. Include in the System Restoration Manual a section delineating actions for the loss of supply to its system, such as occurred in January 2014. (*Conclusion #7.7*)

Chapter VIII: Customer Service and Outage Communications

Conclusions

8.1. Newfoundland Power has made significant progress on the outage improvement recommendations, but important monitoring work remains. (*Recommendation #8.1*)

Recommendations

8.1 Monitor the "customer experience" of the new multi-channel communications services, and adjust the service offering as necessary to ensure a good customer experience. *(Conclusion #8.1)*

The Liberty Consulting Group
2014 Report Addressing Newfoundland and Labrador Hydro

Supply Issues and Power Outages Review Island Interconnected System

Executive Summary of Report on Island Interconnected System to Interconnection with Muskrat Falls *addressing* Newfoundland and Labrador Hydro

Presented to:

The Board of Commissioners of Public Utilities
Newfoundland and Labrador

Presented by:

The Liberty Consulting Group

December 17, 2014

279 North Zinns Mill Road, Suite H
Lebanon, PA 17042-9576

Executive Summary

Background to Liberty's Examination

- The Board of Commissioners of Public Utilities ("Board") retained The Liberty Consulting Group ("Liberty") to examine the causes of widespread electricity outages experienced by customers on the Island Interconnected System ("IIS") of Newfoundland and Labrador from January 2 through 8, 2014. This report follows an April 2014 Interim Report ("Interim Report") from Liberty.
- This report: (a) confirms the outage causes Liberty described in the Interim Report, (b) reports on the actions Newfoundland and Labrador Hydro ("Hydro") has taken to address the directions from the Board's May 2014 Interim Report, the recommendations in our Interim Report, and additional initiatives identified by Hydro to improve service reliability, and (c) describes the conclusions Liberty reached following a review of Hydro's governance, staffing, programs, processes, asset management activities, and performance measurement as they concern longer term efforts to sustain reliability at appropriate levels. Liberty remains engaged in a review (expected to be completed in the spring of 2015) of the reliability impacts that will follow interconnection of Muskrat Falls generation through the Labrador-Island Link.
- Liberty has been serving utility regulators for more than 25 years, working in hundreds of projects across the full range of areas involved in ensuring safe, reliable, and cost effective utility service. Liberty's work extends to 55 North American jurisdictions, ranging from some of the continent's most expansive holding companies to small providers that serve largely rural areas. Liberty has examined reliability and outage response in extreme weather, hurricane, flood, and wind conditions.

Overall Conclusions

- Liberty continues to conclude, in full accord with Liberty's Interim Report, that the outages of January 2014 stemmed from two differing sets of causes: (a) the insufficiency of generating resources to meet customer demands and (b) issues with the operation of key transmission system equipment.
- The introduction of an additional 120 megawatts of generation in the form of a new combustion turbine pursued following the January 2014 outages will make a significant contribution to generating resource sufficiency. Hydro needs to make completion of the unit, now planned to be in service by the end of December 2014, a critical priority.
- Liberty found, however, that even with the installation of the new combustion turbine and new capacity assistance arrangements with certain industrial customers, generation reserves are very low and the risk of outages remains high for the 2015-2017 winter seasons. Hydro must continue to focus on ensuring the availability of all generation units for the winter period.
- Hydro has made substantial progress in addressing its problems that contributed to transmission equipment failures. The actions it has taken will mitigate the risk that such failures may contribute to outages over the next few winter seasons. Continuing action is

required at least through 2015 to complete the necessary work. Hydro also needs to focus on a number of areas that will contribute to improved reliability over the longer term.

- Following Liberty's Interim Report and its own investigations, Hydro established comprehensive plans and schedules for improving supply and addressing transmission performance. Its work in completing the plans has been commendable, although important work remains to be completed.

Generation Resource Sufficiency

- The outages that began on January 2, 2014 resulted from a shortage of generating capacity to meet customer demand. The use of certain planning criteria that Hydro had used for a long period of time, exacerbated by the failure to have certain generating units available for peak periods, contributed to this shortage. As Liberty's Interim Report observed, adding resources and making sure that existing resources are available during winter peak conditions formed first-order priorities for Hydro in 2014.
- Despite adding nearly 200 megawatts of supply capacity through the new 120 megawatt combustion turbine and securing new capacity arrangements with certain industrial customers, supply remains tight until the interconnection with Muskrat Falls. Generation reserves remain very low in our opinion.
- Hydro has made progress in addressing winter readiness, but lingering performance problems with some combustion turbine units remain, and certain activities need to be completed. The Interim Report also addressed concern about identifying and securing parts critical to keep on site at generating units. Hydro made progress in addressing this issue, but did not procure all identified critical spares by December 1. Hydro needs to complete this work as soon as possible.
- Despite the improvement initiatives in 2014, including adding new capacity and Hydro's winter readiness program, generation availability remains a challenge. Hydro needs to continue to place a high priority on completing all work required to ensure that generating units are available for service by December 1 each year.
- With respect to Hydro's planning criteria, Liberty's Interim Report found the need to make improvements in load forecasting as it relates to supply planning. In Liberty's work for this report, Liberty found that Hydro has made major improvements in this area as Liberty recommended, but Hydro should continue to analyze some forecasting details, and make changes to others. Also, Hydro had been using tools for short-term forecasting that have proven unreliable in extreme weather conditions. Hydro has made improvements in this area as well, but their effectiveness remains unproven. The Board should monitor testing of and results under the new methods.
- A major concern identified in the Interim Report was Hydro's use for supply planning purposes of a weather forecast that was too optimistic as it had a 50 percent chance of being wrong in any given year. Liberty stated then and continues to believe that a more conservative forecast (one having only a 10 percent chance) should form the planning base. Hydro has chosen to continue using the 50 percent forecast, but has stated it will model Liberty's recommended case as part of its planning work. Liberty finds that approach acceptable, provided that it remains clear that the 10 percent case must be considered in planning decisions.

- Past conservation efforts have focused on energy savings. Current capacity circumstances, however, dictate a robust consideration of short-term demand-management options. Work in that direction, planned for imminent commencement needs to consider a sufficiently broad range of Muskrat Falls in-service dates, in order to properly assess the pay-back periods of short-term options. Completion of that work needs to be accelerated as much as possible as well.

Transmission and Distribution Systems

- As we found in our Interim Report, the second half of the January 2 through 8, 2014 period experienced more widespread and uncontrolled outages due to Hydro equipment failures. These failures began with a fire at a major transmission system substation and ultimately extended to include major failures at three terminal stations. The number, nature, and short time frame of these failures brought into question Hydro's practices for equipment operation and maintenance.
- Liberty concluded in the Interim Report that Hydro did not complete recommended maintenance activities on the failed equipment, and that protective relay design issues and insufficient operator knowledge of the protective relay schemes existed. Liberty recommended enhanced maintenance practices. Hydro has made substantial progress in making those enhancements, both short and long term.
- Liberty concluded in the Interim Report that Hydro has moved toward the industry best practice of adopting an "asset management" program, which is the industry's common term for optimizing infrastructure performance and costs, including structured, comprehensive maintenance. Hydro's execution of its program, however, had not fully recognized some aspects of inspection, testing, maintenance, and operation that were appropriate, considering the advanced age of some of its transmission system asset types. In Liberty's investigation for this report Liberty found that Hydro has made substantial progress in improving program execution in the areas Liberty's Interim Report had identified.
- In addition to monitoring reports of Hydro's progress in areas covered by Liberty's Interim Report and Hydro's own identification of improvement actions, Liberty reviewed longer term drivers of transmission and distribution reliability for this report. Liberty reviewed Hydro's reliability performance, and examined performance drivers that include system planning, design, operations, asset management, and outage and emergency management.
- Hydro experienced declining transmission reliability performance from 2009 to 2013 even after adjusting for the consequences of major outage events. Overall performance in this area has been below that of Canadian comparators. Distribution performance, however, is consistent with Canadian experience, after adjusting for such events. The 2014 transmission and generation outages will have a significant impact on Hydro's reliability metrics when they are measured after year end.
- Liberty has made a number of recommendations in this report to enhance reliability, including that Hydro should examine its methods for maintaining radial transmission lines to include the use of more portable generation and "hot line" work. Examination of a number of other measures may serve to improve reliability, including: (a) a program dedicating resources each year to address worst-performing feeders, (b) using a metric comparing cost with estimated avoidance of customer interruption numbers or minutes in prioritizing proposed distribution

projects, and (c) changing scoring methods used to prioritize projects, by increasing the emphasis on reliability metrics.

- Liberty found Hydro's design criteria and standards appropriate for its transmission and distribution systems. It uses planning criteria, and it performs load flow, voltage, stability, interconnection, and short circuit studies that conform to good utility practices. Good utility practice calls for full SCADA implementation on both transmission and distribution systems. Hydro, however, does not have this capability on a number of transmission circuits, terminal stations and distribution feeders.
- The Energy Control Center staff, which conducts the operations of the system, has appropriate systems, tools, monitoring equipment, information, organization, staffing, training, role definition, and engineering support. A real-time link permits data sharing between the Hydro and the Newfoundland Power SCADA systems.
- Hydro operates under a manual, paper-based outage management process that does not conform with best utility practices. An electronically based Outage Management System would improve customer service, reliability metrics, communication with outage responders, and accuracy in restoration time estimates provided to customers. Hydro needs to study the costs and benefits of instituting such a system.
- Emergency Operations Centre location, contents, staffing, and role definition conform to good utility practices. While generally sufficient, the Corporate Emergency Response Plan would benefit from more clarity in determining how to classify the severity of outage events. The protocol for determining when and how to prepare for winter events and the rotating outage protocol are also generally sufficient, but should be expanded to address a number of specific items.

Customer Communications

- At the time of the January 2014 outage events, Hydro did not have a customer service strategy in place to guide day-to-day service response or customer service response during outages. Hydro has since created a Customer Service Strategic Roadmap, which comprises a key first step. It remains for Hydro to commit to the funding necessary to carry out this plan's initiatives.
- In response to the recommendations in Liberty's Interim Report, Hydro undertook nine initiatives to improve outage communications and inter-utility coordination. Seven of the nine have been completed with the remaining ones scheduled for completion by year end.
- Liberty reviewed Hydro's relationships with large customers during this phase of our work. Hydro does not have and should develop a key accounts management program to support large industrial and commercial customers, and should conduct customer research to better understand its largest customers.

Governance, Decision Making, and Common Staffing

- The Board asked Liberty to review Hydro's governance and decision making and to examine the approach and structure for providing common staffing among Nalcor's lines of business insofar as it includes Hydro.
- Applying the standard model for utility holding company governance would call for: (a) expanding the range of skills and experience among the directors on Hydro's board, using a

structured assessment of needs that correspond to the nature of Hydro's operations, (b) promoting a time and effort commitment that will broaden and deepen engagement of the directors in operations and service issues, and (c) ensuring that compensation is sufficient to attract a broader range of skills and experience and to ensure the commitment associated with a broader and deeper level of engagement.

- Hydro needs a single executive under which it can consolidate the principal functions associated with delivering utility service. In the current structure the Nalcor CEO has a broad range of other duties that limit his ability to manage Hydro on a day-to-day basis. This new, full-time Hydro executive needs to be in place soon; a leader with proven, top level utility executive experience would be a first choice. Hydro should also restructure its regulatory affairs function to place an executive-level person in charge of that function full time, reporting to the new full-time consolidating Hydro executive.
- The Project Execution and Technical Services Group provide common services in a manner designed, structured, and staffed to benefit Hydro. There is a need, however, to make clear to stakeholders the basis for and the nature of assignments of personnel to Hydro work. Transparency is important to address regulatory and stakeholder confidence that common service organizations do not: (a) leave the utility sector with insufficient resources, or (b) make the utility sector a "sink" for unproductive time costs. There are also valid regulatory and stakeholder interests in how costs are charged and allocated. Liberty did not examine questions associated with this third area of interest, which takes particular and different lines of inquiry from those Liberty was charged with pursuing.
- The events of the past two winters, the continuing low reserves for generation capacity and the age of Hydro's transmission and distribution infrastructure underscore the need for a focus on operating risk. Best utility practice for addressing operating risks is through the use of a comprehensive enterprise risk management program. Hydro has made strong first steps in establishing and implementing enterprise risk management. However, it needs to continue to move its approach forward to make it fully effective in addressing operating risks in a best practices manner.

Supply Issues and Power Outages Review Island Interconnected System

Report on

Island Interconnected System to Interconnection with Muskrat Falls
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I. Introduction

A. Events Leading to the Board's Investigation

The interconnected electrical system serving the vast majority of customers on the island of Newfoundland (the Island Interconnected System, or "IIS") has experienced significant outages in each of the past two winter seasons.

In January 2013 a series of events on the system of Newfoundland and Labrador Hydro ("Hydro") produced Island-wide, extensive customer outages, primarily on the Avalon Peninsula. The next year, in January 2014 conditions on Hydro's system caused two series of outages across the period from January 2 through 8, 2014. Island customers experienced a series of outages whose immediate origins lie in two separate streams of events. First, a shortage in Hydro generating resources caused the institution of a series of rotating outages. Second, as Hydro and Newfoundland Power were recovering from the circumstances leading to and the responses to these outages, a series of equipment and operations issues led to additional outages. The consequences of this second series of events included both widespread, uncontrolled outages and another series of rotating outages.

The shortage in Hydro's generating resources was caused by the unavailability, as January approached, of a number of its generation facilities which were out of service. At the same time, Hydro anticipated very high loads, reaching levels sufficient to threaten its ability to provide continuous service. Customers were asked to conserve energy after 2 p.m. on January 2. At about 4 p.m., rotating outages began. They continued until nearly 11 p.m. that day. Rotating outages resumed for a short time during the next morning's peak load period.

The equipment and operations related outages started on January 4th when Hydro experienced a major fire at one of its Sunnyside station transformers. At about 9 a.m., a variety of equipment failures and the operation of protective equipment caused the loss of generation and transmission capacity serving the Avalon Peninsula. Hydro worked through an extended series of equipment problems, variations in available generation, and operations activities, finally completing the bulk of immediate recovery efforts at around 3:30 p.m. on January 8.

Newfoundland Power reported outages to three-quarters of its retail customers during the two series of events that took place between January 2 and 8 of 2014. Some of them were for extended periods of time. Newfoundland Power attributed 15 percent of its customer outages to the capacity-induced rotating outages of January 2nd and 3rd, and 80 percent to the equipment related outages that followed and finally ended on January 8th. Winter storm conditions coinciding with these events independently produced the remaining 5 percent of outages for Newfoundland Power's retail customers.

B. Scope of Liberty's Engagement

The Newfoundland and Labrador Board of Commissioners of Public Utilities (the "Board") retained The Liberty Consulting Group ("Liberty") to study and report on *Supply Issues and Power Outages on the Island of Newfoundland Interconnected Electrical System*. This engagement followed the Board's determination, under the *Public Utilities Act*, R.S.N.L 1990, c. P-47, to conduct an investigation. The Board's objective in this investigation has been to:

> *complete a full and complete investigation into the issues that are to be identified by the Board on the supply issues and power outages that occurred on the Island Interconnected System in late December 2013 and early January 2014.*

The Board identified issues to be addressed in its investigation following a February 5, 2014 pre-hearing conference and consideration of a wide range of issues proposed by stakeholders, who provided written comments and participated in the pre-hearing conference. Board Order No. P.U. 3(2014) (the "February 19 Order") established the issues to be addressed by Liberty's study and reports thereon.[1]

Liberty was asked to investigate and complete an interim report including an explanation of the IIS events that occurred in December 2013 and January 2014, an evaluation of possible IIS changes to enhance preparedness for the 2014-2016 winter periods, and an examination of each utility's response to the outages. Liberty was also asked to provide a final report including an analysis of the events of December 2013 and January 2014, an evaluation of the adequacy of and reliability of the IIS up to and after the interconnection with the Muskrat falls generating facility ("Muskrat Falls"), and an examination of customer communications and service enhancements for each utility.

Subsequently, in early October, the Board advised the parties that the remaining scope of the investigation would be dealt with in two phases, with the first addressing the adequacy and reliability of the Island Interconnected up to the interconnection with Muskrat Falls and the second dealing with the implications of the interconnection for adequacy and reliability. This report is filed in response to this Board direction.

1. The Interim Report

Liberty filed an interim report on April 24, 2014 (the "Interim Report"), which addressed the issues set out by the Board for that report. The overall scope of the Interim Report included an:

- Explanation of the IIS events that occurred in December 2013 and January 2014:
- Evaluation of possible system changes to enhance preparedness in the short term (*i.e.*, 2014 through 2016)
- Examination of the response by the two utilities to the power issues and customer issues.

2. Purpose of this Report

The review leading to the Interim Report focused on outage causes and identification of measures that Hydro and Newfoundland Power could take to mitigate the risk of outages through the time when Muskrat Falls enters service as now scheduled. The Board's May 15, 2014 Interim Report focused on issues and actions that should be addressed to mitigate the potential for significant outages during the coming winter. The Board also asked Liberty to address longer

[1] **IN THE MATTER OF** *the Electrical Power and Control Act, 1994*, SNL 1994, Chapter E-51 (the "*EPCA*") and the *Public Utilities Act*, RSNL 1990, Chapter P-47,(the "*Act*"), as amended; and **IN THE MATTER OF** an Investigation and Hearing into supply issues and power outages on the Island Interconnected System.

term issues affecting reliability on the IIS. This report provides Liberty's assessment of the adequacy and reliability of the IIS up to the interconnection with Muskrat Falls. It discusses both immediate-term actions to address reliability for the coming winter and identifies opportunities for ensuring reliability of service in the longer term. It also provides our assessment of the progress Hydro has made in responding to the recommendations in the Interim Report and the directions in the Board's Interim Report.

3. Next Steps

We continue to address reliability issues specifically raised by the introduction of Muskrat Falls. We anticipate a Spring 2015 report addressing the issues associated with Muskrat Falls and its link to the IIS.

C. Causes of 2014 Outages

Hydro and Newfoundland Power operate the equipment and infrastructure needed to provide service to IIS customers. Hydro provides the vast majority of the generation (supply) needed to produce electricity and the transmission needed to move that electricity to the areas where customers use it. Newfoundland Power operates most of the distribution facilities of the IIS, connecting end-use customers to the sources of electricity provided by Hydro's generation and transmission facilities.

We continue to conclude, as we reported in the Interim Report, that the January 2014 outages stemmed from two differing sets of causes: (a) the insufficiency of supply (generation) resources to meet customer demands, and (b) issues with the operation of key transmission system equipment. We found at the time that a continuing and unacceptably high risk of outages from such causes remains for the 2015-2017 winter seasons. Our Interim Report identified a number of actions that would improve the ability to avoid outages and to prepare for and respond to those that cannot be avoided.

1. Supply Insufficiency

A shortage of generating capacity to meet customer demand produced outages that began on January 2, 2014. This shortage caused Hydro to request institution of a series of controlled, but substantial rotating customer outages. We found that addressing the continuing risks of supply/demand imbalances would require adding resources and making sure that existing resources are available during winter peak load conditions.

Our Interim Report found, and we continue to believe, that there exists a continuing and high risk of supply-related emergencies until Muskrat Falls and the Labrador-Island Link come into service. That time will be the winter of 2017/2018, at the earliest. A significant source of this continuing risk results from Hydro's modeling of required generation capacity and reserves. Hydro has used its current approach for decades, but its modeling, as currently constructed and used, does not produce acceptable levels of reserves. The work leading to this report examined planning criteria and practices.

More specifically, we found that Hydro's planning in effect averages winter conditions. Given the very large percentage of customers using electric heat, this approach does not give sufficient emphasis to the extreme loads that colder winter conditions can produce. Planning for generation, which uses worst-day winter conditions having a 50/50 chance of being exceeded every year, is not sufficient to ensure continuous service in Hydro's circumstances.

We found also that Hydro's planning basis, as reflected in its historical design and operation of its electric system, makes greater allowance for the use of interruptions than do other North American locations and utilities we have examined. We considered it appropriate to employ a robust, structured examination of how the standards Hydro uses conform to current customer expectations in what we would expect is a changing regional environment. It has generally been the case that North American utility customer expectations have risen.

A second contributor to a shortage in Hydro's supply reserves arises from the problem of generating unit readiness to perform in peak periods. Hydro correctly seeks to make its generation available by December 1 of each year. The goal is to complete required maintenance and repairs by the time that each winter season begins. This goal recognizes the significant probability that Hydro may experience its winter peak loads sometime in December. Hydro did not, however, met that goal for December 2013. We found that Hydro needs to place a higher priority on finishing the work required to support unit availability by December 1. Sound reserve planning cannot assume such availability if Hydro remains unable to support it.

Ordinarily, the addition of major new supply sources takes a number of years. Hydro encountered an unusual opportunity to secure an already-manufactured 120 megawatt combustion turbine that provided the potential for contributing to capacity as soon as the 2014/2015 winter. This source of generation would do much to compensate for the low reserve levels resulting from the use of the planning criteria noted above. We recommended aggressive pursuit of this new source as a first priority effort.

Examining progress in getting the new source on line became one of the areas of the work leading to this report. Our other major focuses in addressing supply sufficiency included reviewing Hydro's efforts to make generating units ready for winter availability, improving short term forecasting methods, and ensuring the availability of spare parts critical to generating unit operation. Concern about the ability to add further generation in the immediate future also made demand reduction efforts an important area of inquiry.

2. Transmission and Distribution Equipment Performance

We concluded in the Interim Report, and we continue to believe, that transformer failure, protective relay design, circuit breaker malfunction, and operator knowledge issues all contributed to the January 2014 outages. Multiple equipment failures also underlay the January 2013 outages. Not only did equipment fail, but failures had consequence beyond what one would ordinarily expect to occur. In the second half of the period from January 2 through 8 of 2014, more widespread and uncontrolled outages resulted from Hydro equipment failures. These failures began with a fire at a major transmission system substation. Hydro ultimately experienced a series of major equipment failures at three of its terminal stations.

We found that Hydro did not complete recommended maintenance activities on the equipment that failed, and that protective relay design issues and insufficient operator knowledge of the protective relay schemes existed. These circumstances contributed to the outages caused by the equipment failures. The unusual number and nature of the failures that occurred within an extremely short time frame made a focus on improvement of equipment operation and maintenance another matter of first importance in this part of our investigation. We found that Hydro needs to: (a) recognize the special needs of aged equipment, (b) identify required inspection, testing, and maintenance activities appropriate to them, (c) establish sufficiently short maintenance cycles, (d) provide the resources needed to rigorously perform planned actions, (e) complement internal resources with outside expertise and resource levels where required, and (f) ensure that operators understand equipment limitations and weaknesses.

The industry has moved increasingly in recent years to adopt “asset management” programs to address key infrastructure components, such as those that caused problems for Hydro in the outages of the past two winters. The term “asset management” refers to a systematic process for the cost-effective operation, maintenance, upgrading, and retirement of such components. Hydro has placed an industry-competitive emphasis on creating and committing to the use of an asset management program. The results observed (*i.e.*, the quality of asset performance) during the outages of the past two years, however, question the effectiveness of the application of the process.

The review leading to the Interim Report led us to conclude that Hydro’s execution of the program gives more visibility to cost effectiveness than to preventing the kinds of equipment failures that have caused widespread outages. Examples include deferral beyond established time cycles for maintenance on equipment that included some that failed in recent outage events. Maintenance backlogs were significant, and had grown since 2011. During this phase of the investigation Liberty examined Hydro’s efforts to improve maintenance performance in recent months and plans to continue sustainable maintenance levels after catching up with existing backlogs.

Effective asset management also requires recognition of and accounting for equipment age. Liberty found Hydro’s maintenance standards more appropriate for a system comprising equipment of “younger” vintage than characterizes Hydro’s infrastructure. The use of now technologically dated air blast circuit breakers comprises an example. Three such devices failed to operate in the January 2014 events. Hydro did not test these devices prior to the January 2014 events, and only began to do so afterwards. We also recommended changes to Hydro’s transformer inspection and test cycles to reflect more appropriately the age and nature of its equipment.

Key recommendations made in the Interim Report include:

- Emphasizing prevention of equipment-related failures as a key component of asset management
- Intensifying equipment testing by assessing and complying with maintenance cycles for aging equipment, including dissolved gas analysis for critical transformers and regular operation of air blast circuit breakers

- Addressing needed relay protection changes, including examination of protection schemes, consideration of the installation of breaker failure relay protection where it does not now exist, and completion of high-priority relay replacement
- Adding the resources necessary to reduce maintenance backlogs and to address relay protection and control issues.

We monitored Hydro's progress in completing a structured and extensive series of actions designed to address these recommendations, along with other, generally related ones, that Hydro's internal assessments identified as appropriate. We also looked at other, longer term issues that may affect the performance of Hydro's transmission and distribution systems. A separate, companion report does the same for the Newfoundland Power System. We began our review with a base review of Hydro's system performance under standard reliability indices. We also looked at transmission and distribution system planning, design, operations, and asset management.

D. Response to Outage Events

The examinations leading to the Interim Report examined customer service accessibility and response and public and media communications in the context of the recent outages. We concluded in the Interim Report that Hydro and Newfoundland Power needed to work in a closely coordinated fashion during major events. Their goals should be common. The customer knowledge that forms the basis for their decisions should also be common. Particularly, their basis for making notifications to customers should be common, robust, and as objective as possible. The need to do so is strongly exhibited by a late request for customers to initiate conservation measures on January 2, 2014.

The principal Interim Report recommendations that address the communications issues at Hydro and Newfoundland Power include:

- Beginning the transition to a system that provides self-service (*i.e.,* without reaching a live representative) for reporting outages and emergencies, and inquiring about restoration status
- Conducting a joint Hydro/Newfoundland Power lessons learned exercise, involving the communications teams of both utilities, and seeking to develop a common set of plans for coordinating communications goals, processes, and interfaces for future major events
- Developing joint and individual outage communications strategies
- Conducting joint customer research designed to improve both Companies' understanding of customer expectations about outage information and conservation requests
- Developing clearer and more comprehensive advance notification procedures for Newfoundland Power customers
- Exploring additional communications channels (*e.g.*, two-way SMS text messaging or broadcasting options) for delivering outage status updates.

During our investigation in this phase Liberty reviewed the actions taken to address these recommendations.

E. Intercompany Coordination

The Interim Report also identified customer and intercompany communications as areas where greater efforts and more coordination between Hydro and Newfoundland Power would prove beneficial. This report examines efforts made in those areas. The needs we identified include: (a) a number of operational data exchanges and protocols and procedures, (b) joint efforts to address communications with customers in advance of and during outages, and (c) undertaking structured, formal efforts to understand more about customer perceptions, attitudes, and expectations about service reliability and outage response.

F. Other Issues This Report Addresses

We also examined in more detail for this report the management of outages and emergencies, including the plans, resources, and principal activities as intended and as actually implemented during the January 2014 events. The scope of the work leading to this report also includes, as requested by the Board, an examination of Hydro's governance, decision making, and staffing. The circumstances surrounding the recent outages raised the matter of how the governance model used by Hydro provides for decision making and how formal considerations of risk ("enterprise risk management") drive decisions affecting reliability. We included a review of that matter as well.

G. Study Approach and Methods

In this phase of our investigation, Liberty's study team first looked again at the nature of the events contributing to the outages and their immediate causes. We did so to determine whether any new information or analysis would cause changes, deletions, additions, or emphasis on the causes determined during the review leading to our Interim Report. We found nothing that would cause us change in our views.

Second, as requested by the Board, Liberty reviewed Hydro's progress in completing the actions recommended to address immediate-term actions for addressing reliability issues. These actions arose from our Interim Report, with which Hydro largely agreed, and from additional effort the Company took to identify improvement opportunities. We performed this review by examining regular Hydro progress reports over recent months and by discussing those reports with management. The methods established for this review did not include field and detailed, underlying data examinations to verify the accuracy of reported conditions.

We met frequently with Hydro management and the teams it had assembled to conduct its examinations and to manage the preparation and execution of its plans to address reliability improvement recommendations. We conducted interviews with executives and managers responsible for the performance of the functions reviewed for the first time in this report, as part of our review of longer term plans, practices, resources, and actions to sustain service reliability. We issued many formal requests for information, and reviewed the responses to them. We again reviewed the reports that each utility filed in response to the Board's directions and we conducted interviews with Hydro and Newfoundland Power management. After assembling a comprehensive set of factual findings, we reviewed them and tentative conclusions with both companies in order to give them an opportunity to identify errors or omissions of fact.

H. Liberty's Team

Liberty used essentially the same team that we used to conduct the review leading to the Interim Report, with one change. We added a senior electric utility veteran whose management experience includes asset management and emergency planning. Each team member has spent 30 years or more in the industry. Liberty's president and one of the firm's founders, John Antonuk, led Liberty's examination. He received a bachelor's degree from Dickinson College and a juris doctor degree from the Dickinson School of Law (both with honors). He has led some 300 Liberty projects in more than 25 years with the firm. His work extends to virtually every U.S. state and he has performed many engagements for the Nova Scotia Utility and Review Board across a period of about ten years.

Mr. Antonuk has had overall responsibility for nearly all of Liberty's many examinations for public service commissions. His work in just the past several years includes: (a) examinations of overall direction of construction program, project management and execution, and operations and maintenance planning and execution at five major utilities, (b) assessment and monitoring of progress against major infrastructure replacement and repair programs, (c) multiple reviews of generation planning by electric utilities, and (d) use of risk assessment in the formation of electric utility capital and O&M programs, schedules, and budgets. Overall, he has directed more than 20 broad audits of energy utility management and operations, and more than 40 reviews of affiliate relationships (including organization structure and staffing) and transactions at holding companies with utility operations.

Richard Mazzini reviewed the planning and generation issues for this report. Mr. Mazzini holds a B.E.E. (Electrical Engineering) degree from Villanova University and an M.S. degree in Nuclear Engineering from Columbia University. He is a Registered Professional Engineer in Pennsylvania, and is a member of the American Nuclear Society and the Institute of Electrical and Electronic Engineers. He has managed broadly scoped management audits of a number of large electric utilities for Liberty. His broad experience in the electric industry includes very senior positions with a number of global consulting firms. He has assisted many utilities and other energy-related firms in the U.S., Canada, Europe, and the Caribbean. Prior to entering the consulting business in 1995, he had a long career in key management positions at a major northeast electric utility.

Mr. Mazzini has consulted extensively in the areas of bulk power planning and operations, power procurement (including energy marketing, trading, and risk management), cost management, system reliability, emergency management, strategic business planning, and utility operations. He has considerable experience with electric system reliability, emergency planning and management, and major outage restoration programs and actions. He was responsible for the emergency management elements of a major audit of New York's largest utility in the wake of a number of large-scale outages. His recent work for Liberty includes: (a) leading a project designed to enhance aging electricity system infrastructure to improve reliability, (b) examining generation planning involving both new units and extending the lives of existing units, (c) evaluating the emergency management functions of a major electric utility operating as part of a holding company, (d) evaluating the appropriateness of major storm costs and their recovery in rates, and (e) reviewing the use of risk management in planning of capital and O&M initiatives and programs for electricity generating units.

Mark Lautenschlager is a widely recognized expert in electricity transmission and distribution equipment and systems. His particular areas of expertise include electrical testing and maintenance, substation design and construction, forensic investigations of failed equipment, and technical training of electrical testing and maintenance technicians.

Mr. Lautenschlager has been conducting T&D reliability evaluations for Liberty for more than ten years. Most recently, he led Liberty's review of electric system operations in a management and operations audit of a utility engaged in a major program to address a series of weather-related, major outages. He focused on maintenance, construction, and root cause analysis. He has performed similar work for Liberty at nine major electric companies, including a number of Maine and Nova Scotia utilities. Before beginning his consulting career, he held substation maintenance and relay engineering positions in the electric utility industry, and ran a business focused on training electrical maintenance technicians and engineers, developing RCM-based substation maintenance programs, and performing forensic investigations of electrical equipment failures.

Mr. Lautenschlager is a registered professional engineer in Indiana, Ohio, and Pennsylvania, and holds a B.S.E.E. degree. He is a past president of the International Electrical Testing Association, and has been active in developing ANSI electrical equipment maintenance specifications.

Christine Kozlosky examined customer service and communications issues for this report. A nationally recognized utility customer service expert, she has worked with Liberty on many projects over 17 years. Her recent work with Liberty includes reviews of customer service and communications on four recent, broad management and operations reviews of major electric utilities, and on one project focusing specifically on customer service and communications. She has conducted many reviews of customer service and communications in the context of outage preparation and response, most recently in New England. She has also conducted base and follow-up reviews of outage communications at Nova Scotia Power as part of Liberty's engagement for the Utility and Review Board. This review examined storm response and communications.

Her earlier work in reviewing customer service and communications for Liberty includes four electric utilities, four natural gas utilities, and two telecommunications utilities. Ms. Kozlosky has been providing customer service performance benchmarking and performance improvement consulting since the early 1990s. She has conducted significant research into customer care best practices, process improvement, and performance benchmarking. She has a B.S. in Information & Computer Science from Georgia Institute of Technology.

Philip Weber was added to the Liberty team for the work for this report. He has over 35 years of professional experience in the electric utility industry specializing in reliability and maintenance of electric distribution systems, planning, and construction and project management. Phil managed the reliability and maintenance of the transmission and distribution system of a major

Northeast electricity supplier, PPL, where he produced major improvements in SAIFI and SAIDI performance.

Phil served on Liberty's team tasked with Development of a Long-Term Electric & Gas Infrastructure Improvement Plan on behalf of NorthWestern Energy. He also served on Liberty's management reviews of East Kentucky Power Cooperative and Southwestern Public Service.

During a long career at PPL, Phil served as Project Manager in the Systems Operations Department, overseeing consolidation of the transmission operations function (69 kV and above) to a single office, while simultaneously managing the separation of the transmission operations function from the distribution operations (12 kV) function, and consolidation of regional offices. He also served as the System Maintenance Engineer, where he managed the reliability and maintenance of the transmission and distribution system, including the inspection and maintenance of 27,600 miles of overhead and 6,000 miles of underground circuits and related devices, managed the vegetation management program, administering an annual budget in excess of $50 million. He also had extensive experience in planning and managing storm response for the utility. Phil holds a B.S. in Industrial Engineering and a M.S. in Management Science from Lehigh University. He is a Registered Professional Engineer in Pennsylvania.

II. Planning and Supply

A. Background

This chapter addresses the following supply-related areas:

Load Forecasting *Reserves* *New Generation* *Interruptible Load* *Unit Availability*

It also addresses the execution of the Asset Management Program as it concerns generation assets. The next chapter discusses programmatic aspects of Hydro's asset management and approach which apply commonly to generation, transmission, and distribution assets.

1. Load Forecasting

Load forecasting capabilities enter into the investigation of the 2014 supply emergency in at least two important ways. First, Hydro's forecast of future loads and how those forecasts are applied determine the amount of generation required. Second, short-term (week-ahead) forecasts serve a critical system operations function, allowing Hydro's operators to balance load and generation effectively. When adequate generation was not available during the 2014 emergency, the short-term forecasting tool proved inaccurate in the extreme. Accordingly, Hydro's capability to forecast load accurately became a matter of primary focus in our earlier work.

Liberty's load forecasting concerns and recommendations covered short and long-term forecasts. On October 31, 2014, as directed by the Board, Hydro issued a report on the improvements to its load forecasting capabilities[2]. That report addressed recommendations by Liberty and Hydro's internal review. The report outlines Hydro's actions which responded to all of the recommendations, and went further in implementing some additional improvements.

2. Supply Adequacy

Liberty's 2014 Interim Report attributed the initial problems in January 2014 to a shortage of supply. Liberty found many factors contributed to the supply shortage, including:

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

3. The New CT

Following the January 2014 outage events, Hydro committed to and has been aggressively pursuing the installation of a new, 120 MW combustion turbine generating unit. Its ability to complete installation, now planned for the end of this December, is a matter of first priority in ensuring sufficient supply to meet winter conditions.

[2] *A Report to the Board of Commissioners of Public Utilities, Progress Report on Load Forecasting Improvements*, October 31, 2014.

4. Interruptible Load

Interruptible load offers the potential for avoiding otherwise needed capacity long term. In the short term, its active pursuit has been important in addressing a supply shortage.

5. Unit Availability

The supply planning criteria and process were primary factors in the 2014 supply emergency. Unit availability was also a prime contributor. Hydro faced unusual availability circumstances at the time; *i.e.*, a number of partial capacity reductions, rather than the more typically encountered full loss of units. Supply issues commonly surface when unusual and extreme weather conditions apply. Such conditions often take down full units, and even full stations. Hydro faced a far different situation. Only Hardwoods Station (50 MW) suffered a full loss of load. Partial unit losses made up the other 183 MW of unavailable capacity. Losing one or a few large units in extreme conditions is not inherently troubling. However, Hydro's many small de-ratings, most of which did not arise from weather conditions, raises significant questions. Liberty considers the challenge of availability improvement a high priority for Hydro and a continuing matter of major importance.

The Board directed Hydro to file a generation master plan for winter preparation, including a plan to improve availability of its generating units and to assure the presence of critical spare parts at all of its generating units. Hydro filed this on June 16, 2014. Subsequent Hydro plans focusing on winter preparation were issued on August 29, October 1 and December 1, 2014. Liberty has evaluated these plans and tracked implementation progress towards completion for the winter of 2014-15. The areas that Liberty examined are:

Management Analysis	*Maintenance*	*Capital Projects*
Critical Spares	*Winter Preparedness*	*Other Initiatives*
	Asset Management	

6. Conservation and Demand Management

Addressing the sufficiency of reserves will remain an important priority for Hydro until the interconnection with Muskrat Falls. Given the circumstances, conservation and demand management may play a material role in addressing needs during this interim period. Our examination of conservation and demand management focused on programs and initiatives affecting customers on the IIS, recognizing that efforts to address other retail customers exist as well. The subject of energy conservation arose in Hydro's 2006 General Rate Application ("GRA"). The Company completed a study of conservation and demand management potential in 2008.[3]

B. Chapter Summary

Liberty's 2014 Interim Report addressed the areas listed above. This report discusses Hydro's actions to address these areas in 2014, the effectiveness of those actions, and the implications for the future.

[3] Response to #PUB-NLH-436.

The initiatives taken by Hydro during 2014 represent a substantial effort to improve capabilities. Although Liberty found some of these to be incomplete or unclear, this does not detract from the scope of the improvement effort and the successes it has achieved. On balance, Liberty believes Hydro's efforts in this regard were positive and successful, and the remaining actions can be completed in the near term.

Liberty's Interim Report outlined our findings that the generation-related events of the 2013-14 winter resulted from an insufficient amount of available generation. The amount of generating reserves began at less than desirable levels due to a number of Hydro practices. Then, when an unusual amount of capacity became unavailable at a time of peak load, supply could no longer meet demand. This imbalance led to a series of rotating outages initiated via manual load shedding.

The events of January 2014 precipitated a number of studies and reviews, including the review described in our Interim Report. Hydro has also employed experts, vendors, and consultants. A clear understanding of what happened and why has resulted. This chapter of our report addresses the actions taken since those studies and reviews to support efforts to meet future power supply requirements. The time period addressed extends from the upcoming winter of 2014-15 to the years before Muskrat Falls and the Labrador-Island Link come into service.

Our earlier work emphasized three avenues available to Hydro to bolster its reliability of supply:

Additional Generation *Reduced Load* *Higher Unit Availability*

Hydro has responded actively in each area during 2014 and its efforts have produced significant advances. Nevertheless, the IIS remains vulnerable to supply shortages in the years ahead. Aggressive management of the supply situation will continue to be essential at least through the interconnection with Muskrat Falls. Similarly, a promptly executed examination of demand-side alternatives, performed jointly with Newfoundland Power, should have a high priority.

To address the issue of the amount of available generation, Hydro moved to add 120 MW of new generation in the form of a new combustion turbine and to secure 75 MW of interruptible load. The resulting increase in reserves of nearly 200 MW that results after installation of the new generation and finalization of the interruptible load demonstrates a major accomplishment, and one neither envisioned nor even thought possible earlier in 2014. Even with this substantial capacity improvement, when completed, other factors keep capacity a "front burner" issue. Adding nearly 200 MW will produce real gains, but changes in planning requirements and assumptions materially offset them.

Examining the future needs of the IIS requires sensitivity to the matter of cost. Electricity consumers face added costs as the corrective measures of the past year find their way into rates. Looking forward, however, we do not see the need for added extraordinary expenditures in the supply area prior to the interconnection with Muskrat Falls. The opportunities for improvement that this report chapter addresses are not relatively costly, assuming that Hydro does not face load increases not now expected, and assuming further that generating unit availability does not decline. Either of those two significant risks, could create the need for more generation, which would entail significant added cost.

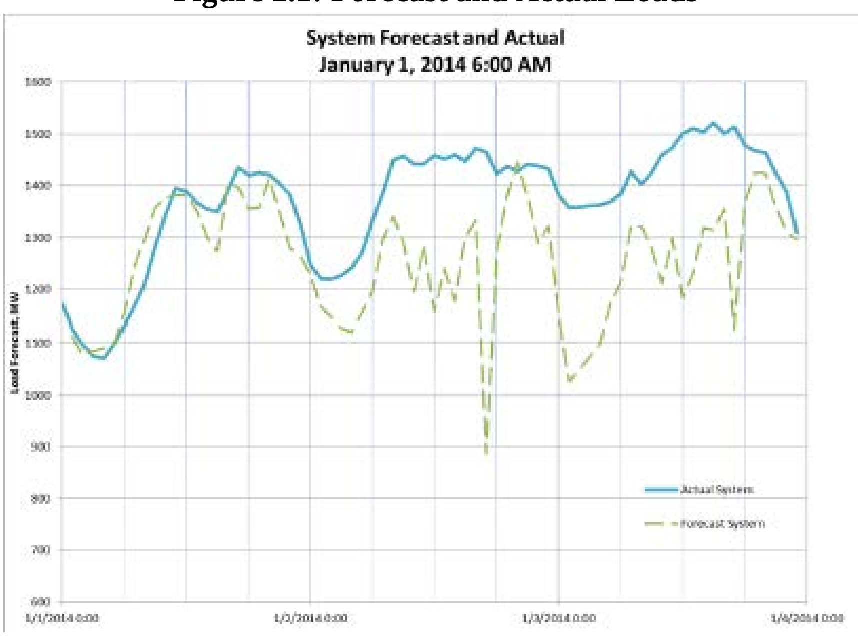
C. Findings

1. Load Forecasting

a. Short-Term Forecasting - Nostradamus

Nostradamus, a neural network program provided by Ventyx, has served as Hydro's primary tool for short-term forecasting. Nostradamus "learns" from actual data, and continuously improves its ability to predict short-term loads. It became apparent to Hydro in December 2013 that Nostradamus was not predicting load accurately. Moving into 2014, the deviations were substantial as illustrated in the following figure.[4] The difference between forecast and actual loads rose to the hundreds of MW, reaching 900 MW at one point. System Operators, aware of the unreliability of the data, worked around the situation by calling upon other methods, and applying their experience. Liberty observed no operating errors or service interruptions that resulted from this problem. Nevertheless, the lack of reliable data complicated matters for the operators at a particularly difficult time. Inaccurate low forecasts hamper Hydro's ability to respond in a supply emergency, cause delayed communications to customers and reduce the ability to plan for and mitigate shortages.

Figure 2.1: Forecast and Actual Loads



Hydro acknowledged the Nostradamus failure in March 2014 in its load forecasting report to the Board, which also included a more detailed assessment by Nostradamus's supplier, Ventyx. Hydro's report attributed the failings to unusual temperature and wind conditions that were "outside of [the model's] learning database." An extensive effort to correct the deficiencies remains in progress.

[4] Response to RFI #PUB-NLH-153.

Hydro's actions to improve Nostradamus included a training workshop with the tool's supplier, new training parameters and procedures, database changes, and development of new forecasts. Hydro has moved the new software and model to the production environment. Hydro is also changing its procedures to provide for review of Nostradamus forecasts monthly (versus quarterly), with retraining to occur this winter.

Hydro's October 31, 2014 load forecasting report provides detail on the improvements that have been made to the model and to the short-term forecasting process. These include:

- Degree of cloud cover as a training parameter
- Use of three-day moving average to enable modeling of persistent hot or cold weather
- Degree of daylight training parameter
- Limiting the training period to more recent data
- Use of fewer meteorological stations
- Emphasis on meteorological data quality
- Increased frequency of forecasting "today's" load
- Multiple weather forecasts.

Additional process changes address at least two natural limitations of the model. First, as seen in 2014, the model failed under unusual weather conditions; *i.e.*, conditions not "learned" by the model. When Hydro's operators know that weather conditions outside the model's abilities arise, they will need to make adjustments in the short-term forecasts. Second, Hydro's operators will forecast industrial load outside of the model, and add it to the Nostradamus results.

The improvement program associated with the model has been an extensive effort by Hydro that will enhance forecasting capabilities. The extent to which those enhanced capabilities fully meet Hydro's needs is not yet known, and will not be until added experience is gained. Judging the effectiveness of the changes will take time following their implementation.

b. Short-Term Forecasting - Representation of System Losses

Liberty's 2014 Interim Report expressed concern that unexpected system losses materialized during the 2014 emergency with an unanticipated load increase of 30-40 MW. The increase arose from the unusual configuration of the system at that time with an unusually large amount of generation off the Avalon Peninsula supplying load there. This increased transmission flows produced higher-than-expected losses.

In response to this finding, Hydro conducted analyses to determine incremental transmission losses resulting from various generation configurations. Hydro is also expanding this analysis to include various 230 kV transmission contingencies. This work has produced a guide that operators can use to adjust the short-term load forecast under abnormal conditions.

c. Island Interconnected System versus Hydro Load

In the past, Hydro has generally reported load data on a "Hydro system" basis, as opposed to load on the IIS. We understand that there is agreement to standardize on an IIS basis and we recommended that the IIS focus be adopted. That decision has now been implemented.

d. The Weather Variable

The "weather variable" comprises the set of weather assumptions assumed by a utility in determining its peak load forecast. Hydro employs 30 years of wind-chill data, selecting the worst day for each year. The average of these 30 data points becomes the basis for the peak load forecast. The 30 data points can be considered a probability distribution and the average will fall at about the 50 percent point. The use of this point is referred to as a P50 forecast in that there is a 50 percent chance that this value will be exceeded (or not exceeded) in any given year.

Liberty's Interim Report recommended that Hydro adopt a higher probability than P50. A consultant to Hydro offered a variation of this recommendation, suggesting instead that higher probabilities be considered as sensitivity cases when Hydro applies forecasts to power supply decision-making. For example, a P90 forecast would mean that the value would be exceeded only 10 percent of the time (*i.e.*, once in 10 years), rather than the once every other year frequency of the P50 value.

Liberty continues to believe that the rationale for using a P50 forecast as the base forecast remains unconvincing because of the likelihood that it will be exceeded so frequently. Moreover, such a low probability forecast increases the exposure that when it is exceeded, it will be by more extreme amounts. The impact may prove very substantial. Hydro reports the difference in required capacity between P50 and P90 amounts to 57 MW.

As suggested by its consultant, Hydro has used the P90 forecast (and the corresponding 57 additional MW) as a sensitivity case in its power supply discussions. The difference here is whether one considers P50 or P90 to be the planning base, with sensitivities examined around that base.

e. Unusual Peak Forecast Variances

The 2013-14 winter brought many peculiarities. From a statistical perspective, the degree of peak exceedances versus more typical years perhaps comprise the most remarkable. Liberty observed that the actual *annual* peak exceeded that forecasted in all four months of the 2013-14 winter, which is highly unusual. In the 39 prior winter months, a monthly exceedance happened only twice. Moreover, one of those was by only 2 MW.

Liberty's Interim Report recommended that Hydro analyze the data in an effort to determine why a presumably rare occurrence would repeat itself in all four months of the past winter. The issue is whether an extreme weather event simply repeated itself in all four months, or were there other forces, such as system anomalies or forecasting errors, that came into play. Liberty has already seen that unexpected system losses had a real impact; perhaps other unusual factors existed as well.

Hydro's October 31, 2014 load forecasting report observed that, "Considerable analysis has been completed to identify the reason for the discrepancy and identify actions to improve the forecast." Hydro also reported that its "review of these events concludes that the prevailing weather conditions during the winter of 2013/14 were a significant contributor to both the system peaks and higher loads for all winter months in general." In support of this conclusion, Hydro described several weather anomalies, and provided charts depicting the unusual nature of that winter's weather. Hydro did not include a direct, quantified correlation between actual weather and actual peaks. This conclusion contravened Hydro's assessment from earlier in the year. We reported earlier that, "Hydro seems to have ruled out weather as a common cause, because historically extreme conditions did not accompany any of the peaks."

f. Reconstructing Peaks

The actual peaks achieved in any given year provide a key input to the load forecasting process. It remains important, however, to consider factors that make those actual peaks deceptively low. This phenomenon occurred in the winter of 2013-14 when large parts of the system were interrupted, when load shedding was employed, and when the public responded to conservation requests. Conversely, loads can become higher due to factors such as cold load pickup following interruptions. Hydro emphasized the difficulty in estimating what its peak loads may have been absent these distortions. Liberty nonetheless recommended that Hydro: (a) strengthen its capability to reconstruct the peak loads, and (b) use the resulting knowledge to analyze the 2014 deviations.

Hydro responded to this recommendation with a "review of system load during the supply disruption." Section 4.2 of its October 31, 2014 load forecasting report addresses this review. The analysis presents *estimated* peak demand based on the actual weather conditions, and compares it to *estimated* peak demand based on average historical peak weather conditions. Hydro seems to suggest that it can best reconstruct the peak by applying actual weather to the established forecasting process.

g. Other 2014 Initiatives and Improvements

In addition to its responses to Liberty's recommendations, Hydro also addressed a number of other load forecasting topics in an effort to improve its capabilities further.

The Newfoundland Power load forecast provides a critical input to the Hydro IIS forecast. Hydro requested information from Newfoundland Power on the range of uncertainties of its forecast in order to better understand possible variations. Newfoundland Power reported that peak demand during extreme cold weather could vary upwards by 60 MW, while the peak may vary 60 MW downward in mild weather. Newfoundland Power also suggested that the 2014-15 peak may vary up or down by 35 MW from forecast.

Hydro also reexamined coincidence factors. Utilities use coincidence factors to combine peaks from different loads when those peaks occur at different times. For example, when peaks occur at the same time, they can be added together to determine the system peak. However, when they occur at different times, the impact on the system peak will be less than the sum. The conclusion is that higher coincidence factors are appropriate, but with a minimal effect (<10 MW) on forecasted peaks.

Any examination of load forecasting must consider the large role of residential electric heat. Hydro has expanded its knowledge base in this area during 2014 by:

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

Hydro has also reevaluated its historical weather data. As a result, the P50 weather condition is now estimated to be 1 degree lower. Hydro estimates this impact at <10 MW.

2. Supply Adequacy

a. 2014 Initiatives

Liberty's 2014 Interim Report made a number of recommendations regarding power supply which addressed the need to:

- Make the securing of new generating capacity a first priority, seeking, if possible, an in-service date of December 1, 2014
- Model system supply needs on the basis of weather assumptions that assume worst-day weather more extreme than the use of long-term averages (P50) would produce
- Improve the accuracy of tools that consider the effects of extreme weather
- Evaluate the causes of deviations between forecasted and actual winter loads
- Accelerate implementation of a program better to ensure unit availability (*e.g.*, through more aggressive completion of maintenance outages) as winter peak seasons approach
- Continue discussions with large customers about interruptible service arrangements.

This report will discuss Hydro's actions to address these recommendations. Those actions have generally proven successful. Hydro's power supply planning vision, approach, and capabilities have grown considerably in the past year. Hydro needs to continue along the path these recent changes foreshadow in addressing future power supply decisions. Continuation is important in ensuring the application of sound and prudent principles and methods.

Perhaps the most significant action taken by Hydro in 2014 is the pending addition of 120 MW in new generating capacity and the potential of 75 MW of interruptible load. One might have expected additions of this size to mitigate pre-Muskrat Falls supply risks thoroughly. As explained below, however, circumstances facing the IIS mean that significant near-term supply threats remain.

b. Forecasted Reserve Margins

A review of Hydro's reserves pre-Muskrat Falls produces two major conclusions. First, forecasted reserves remain under 15 percent for each year except the pending 2014-15 winter. Second, even though the coming winter's reserves rise above 15 percent, they drop to 155 MW (only 8.7 percent) without the new CT. The table below illustrates the current capacity situation, assuming the new CT is in service and 75 MW of interruptible contracts are in place.

Table 2.2: IIS Reserve Capacity

	IIS Peak Demand	IIS Peak at P90 (+57)	Capacity at Peak	Add 75 MW int.	Reserves (MW)	Reserves (%)
2014-15	1,721	1,778	1,978	2,053	275	15.5%
2015-16	1,736	1,793	1,978	2,053	260	14.5%
2016-17	1,755	1,812	1,978	2,053	241	13.3%
2017-18	1,757	1,814	1,978	2,053	239	13.2%

This reserve depiction differs substantially from assessments made in prior years. Most notably, the use of the P90 weather assumption, adds 57 MW to demand. On the other hand, new capacity (120 MW) and new interruptible load (75 MW) are in the process of being finalized. The net effect will be added reserves, but margins will remain limited. The new CT looms large in this discussion in that the consequences of not having made the decision to add that capacity in the immediate term become evident. Looking at the supply picture absent the CT also highlights the urgency of getting the unit in-service as soon as possible.

c. Defining "Adequate" Reserves

Generation reserves are typically calculated by a probabilistic approach that results in a loss of load probability or an estimated loss of load hours ("LOLH"). North American utilities generally employ a criterion of one chance in ten years of a supply-related interruption. Hydro uses an LOLH of 2.8 hours, which equates to a one chance in five years criterion. This criterion has been in effect in Newfoundland for many years as the most practical choice on the basis of economics.

The choice of an LOLH and its application to power supply planning has major ramifications. Liberty's Interim Report suggested that the reserve capacity in terms of a percentage of forecasted system peak load was a more practical measure of power supply adequacy for Hydro. Specifically, the LOLH of 2.8, coupled with Hydro's modelling assumptions, suggested that reserves in the 10-12 percent range were acceptable. While the definition of "adequate" is subject to debate, Liberty believes that meaningful discussion of that definition should center around margins higher than 10-12 percent.

Two assumptions are critical to addressing LOLH adequacy: the assumed appropriateness of the 2.8 criterion and the unit availabilities assumed by Hydro. Had Hydro modeled a lower LOLH (*e.g.*, a one in ten-year probability) and higher forced outage rates, its resulting estimate of required reserves would move higher.

LOLH in one form or another has extremely widespread use. Liberty does not question its value, but a utility should apply the criteria judiciously. Our experience is that acceptable values for reserve margin also require the use of more intuitive considerations. This observation has particular applicability for small, isolated systems, which lend themselves to practical considerations. For example, the impact of a 10 versus a 15 percent reserve becomes far more apparent to the observer than similar variations in LOLH.

In determining an adequate value for reserves, one must first consider the contribution to margins of Hydro's thermal generating units.

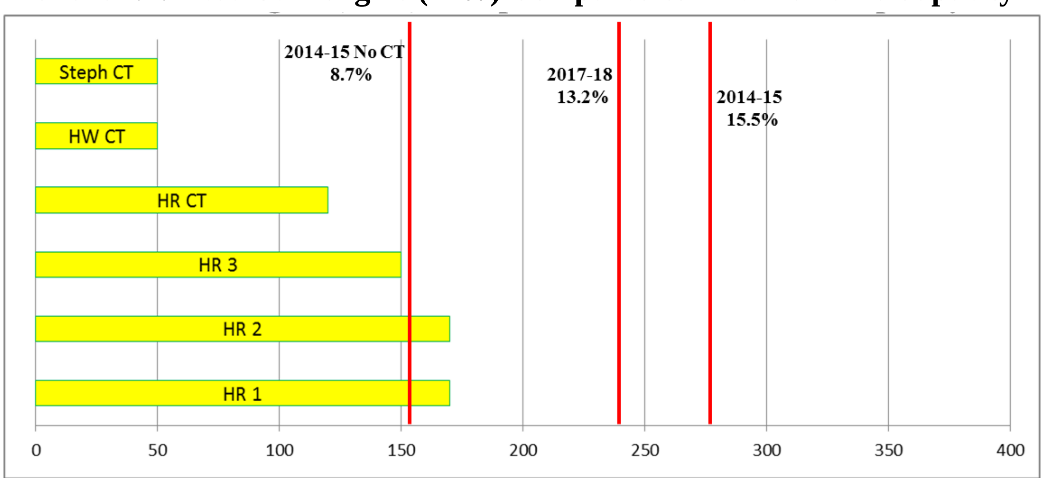
Table 2.3: Thermal Generation as a % of 2017-18 Load

Thermal Generation as a % of 2017-18 Load	
Holyrood 1	9.4%
Holyrood 2	9.4%
Holyrood 3	8.3%
New CT	6.6%
Hardwoods	2.8%
Stephenville	2.8%

To put this in perspective, a 10 percent reserve margin would be essentially wiped out with a single contingency; *i.e.*, the loss of one Holyrood unit. Whatever an LOLH analysis might show, one should conclude that a 10 percent margin brings very high risk. In particular, the 2014-15 reserve of 8.7 percent that would exist without the new CT is problematic.

Clearly, the loss of a large unit calls for examination in reliability analyses. The contingencies that require analysis, however, do not limit themselves to the largest units. The 2013-14 circumstances did not include any large unit outages. The only unit that was totally unavailable was a 50 MW CT. Loss of a large unit becomes even more troubling when it anticipates a number of partial outages to be present concurrently. It does not take much in the way of assumed full or partial outages to gain confidence that margins in the mid-teens are appropriate. For example, the chart below shows that one large unit and a small fraction of the 233 MW lost in 2014 erodes the entire available margin.

Chart 2.4: Reserve Margins (MW) Compared to Thermal Unit Capacity



Such examples make apparent the potential consequences of margins approaching the 10 percent level. Risk may not be so clear when looking solely at LOLH. Using LOLH alone in examining a small, isolated system (like the IIS) can produce a sense of security that belies the risks involved.

Comparing reserve percentage with the capacity of individual units makes the danger of low reserves quite clear.

If reserves approaching 10 percent are too risky for a small isolated system, the question that remains is how to determine an appropriate level. Hydro finds itself in an unusual situation with respect to this question. It will add a large unit (the CT) imminently and it expects a massive capacity addition in a few more years with Muskrat Falls. The value of adding more capacity in the interim should be questioned in these circumstances. Prudence requires close analysis of the ability to “make do” over this comparatively short period. Close and active management is an appropriate option at this time. Therefore, rote application of a fixed target for reserves in the near-term may not prove wise. The key to remaining close to the situation and active in managing it is to prevent reserves from falling to clearly dangerous levels. Accepting ever lower levels of reserves must only take place with a full understanding of the risks and robust plans to mitigate those risks to the extent practical.

d. Risks and Mitigation

Liberty’s Interim Report concluded that there will remain a continuing, unacceptably high risk of supply-related emergencies pending the introduction of Muskrat Falls. Hydro has sought to mitigate to some extent this risk with the efforts with: (a) the pending addition of 120 MW of new capacity, (b) up to 75 MW of interruptible load, and (c) completing a successful maintenance season that includes a more aggressive program of availability improvement. Cautionary notes, however, should temper optimism about the sufficiency of these measures alone considering: (a) reserves remain under 15 percent, (b) there remains a large dependence on four big thermal units, and (c) the very low forecast for growth in peak demand (only 0.6 percent per year) leaves little room for surprises. On balance, Hydro has improved the situation as much as could have been expected in the time period available, but the low reserve margins that remain leave higher-than-desired risk. Attention should turn to how risk can be further mitigated.

Figure 2.5: The Options to Mitigate Supply Shortages

The addition of more generation at this time, with reserves at least borderline, would appear not to be economic. Should availability decrease or load increase, new generation may prove necessary, but until one of those eventualities becomes a real threat, the high cost of more generation should rule out that option. Meanwhile, the 2014 effort to secure new interruptible load suggests that further potential there does not appear promising. Accordingly, availability becomes the remaining variable. We consider unit availability now even more important than before. Forecasted outage rates simply must be maintained or reduced. Hydro does not have room for deterioration in performance with respect to generation availability. Any changes for the worse in availability require prompt recognition, analysis of their impact on supply reliability, and development and implementation of prompt and aggressive corrective measures.

3. The New CT

Hydro had foreseen the possible need for new, pre-Muskrat Falls generation for a number of years. Strategist runs in 2008 suggested a capacity deficit by 2012. However, load supporting that future deficit calculation did not materialize, pushing the forecasted deficit out in time. The November 2012 generation planning issues report stated that "the island system can expect capacity deficits starting in 2015," identifying a solution as a 50-60 MW CT. Hydro did not authorize work on a new CT, however. It chose to wait and see whether the expected load would develop, to account for the possibility that load would again fail to materialize. Load did not develop prior to the 2013-14 winter and the proposed CT therefore did not proceed. However in early 2014, it became apparent that new generation was essential.

Hydro addressed this issue in its March 2014 Generation and Reserve Planning report. Its consultant completed an analysis that formed in part the basis for Hydro's report (attached as Appendix 1 to that report). Hydro's generation options then under consideration included the previously planned, new 50 MW CT (for a December 2015 in-service date) or an already-manufactured CT that could be procured and possibly placed into service earlier (for the 2014-15 winter).

Liberty met with Hydro to discuss the report and increasing concern about the supply situation between the 2014-15 winter and the introduction of Muskrat Falls. These discussions supported Liberty's conclusion that there was a "continuing and unacceptably high risk of supply-related emergencies until Muskrat Falls comes into service." In late March 2014, Liberty met again with Hydro to encourage aggressive action. Hydro promptly began the steps necessary to make a significant supply addition as soon as possible, hoping to do so for the winter of 2014-15. At that time, there was no assurance that such an addition was possible so early. Hydro purchased an already-manufactured 120 MW CT that it had already been examining, for installation at Holyrood Station. Rapid progress has been made, although, at this writing, it is not clear that the December completion date will be met. Nevertheless, Liberty found the procurement, engineering, and construction efforts to get the unit into service by this December commendable.

4. Interruptible Load

Hydro has treated interruptible load as a part of its response to supply needs. The interruptible load secured in early 2014 helped in mitigating the supply shortage that existed.

Hydro developed a plan for soliciting interruptible load, and reported on progress in pursuing that plan into the fall of 2014. That plan is now reported as complete, with Hydro arranging for two sources of interruptible load, one of 60 MW the other of 15 MW. This amount corresponds well with views of the practical limits applicable.

5. Unit Availability

e. Management Reporting and Analysis

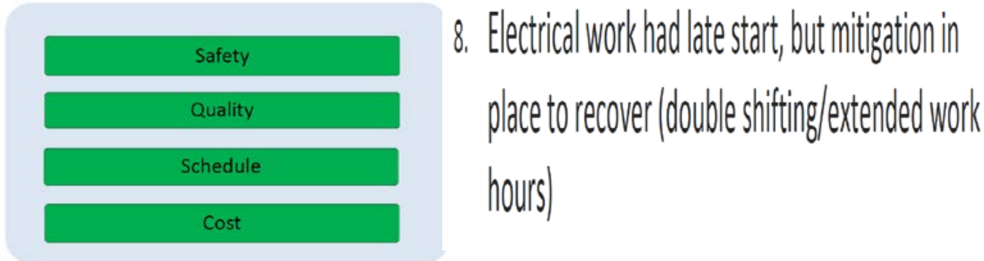
Given the Board's decision to monitor Hydro's progress towards its availability commitments, Liberty worked with Hydro to implement reporting approaches. Hydro reported to the Board on that basis throughout the second half of 2014. Liberty reviewed these reports, discussed them with Hydro, and visited Holyrood and the CT construction project twice.

The reporting structures developed generally worked well. Hydro made timely reports that outlined their actions taken. As months progressed, the Board responded to issues observed in the form of letters requiring action or further information. Throughout the process, however, Liberty remained concerned about Hydro's summary evaluations of progress, which served as the key performance indicators in most areas. Discussions with Hydro produced a green-yellow-red system as its conscientious use would provide early warnings of any emerging issues meriting immediate attention by Hydro and to provide necessary information for the Board. Liberty did not gain confidence that this approach was working successfully, because Hydro essentially continued to report status on all measured items as "green."

Hydro agreed that the purpose of such a system is to alert management to potential problems. Liberty observed, however, that Hydro appeared to include in its definition of "green" items that were behind schedule but for which it expected to "catch up." Our concern with this definition was addressed with Hydro early in the process. Hydro agreed to revise the practice so as to report the "catch up" items as "yellow." The reason for requesting this redefinition was clear and consistent with the view of effective project management reporting. Specifically, if a key activity is late, management needs an early alert, which enables it to ensure definition and monitoring of corrective measures, and direct intervention if appropriate. Otherwise, the risk exists that management will remain unaware of a material issue until options for addressing it become limited or gone altogether.

Liberty's observation has been that Hydro seemed to continue reporting without making (in practice) the change to address catch-up items as "yellow." Liberty continued to observe "green" reporting for items behind schedule. The construction schedule associated with the new CT provides a particularly notable example. Hydro's October 10, 2014 status briefing reported status in all areas as "green." A list of ten Hydro observations, however, noted late electrical work and a substantive mitigation effort including a second shift and an extended workday (see the following depiction). Liberty discussed this matter with Hydro at the time, and became satisfied that appropriate actions were underway. The significance here, however, is that the base reporting should have highlighted the threats to progress. Hydro changed schedule status to "yellow" a month later. That change was too late, and, in any event at that time, should have produced a "red" status.

Figure 2.6: Electrical Work Observation



b. Maintenance

Timely completion of maintenance on generating units is necessary to ensure their availability for the winter season. Liberty sought to verify the existence and execution of a viable maintenance plan that includes suitable methods for tracking and analyzing progress.

Hydro defines maintenance activities in work orders that it enters into a management system. Hydro generally categorizes work as preventive or corrective maintenance. Each work order gets an assigned priority, a "condition" (*i.e.*, what condition the plant must be in to complete the work order), and a reason. The reason for preventive items will include reliability. Hundreds of annual work orders typically exist for each unit.

The "plan" to complete maintenance work orders, at its lowest level, comprises a listing of the scheduled work orders. It is reasonable to consider the list complete and accurate. Further, at a higher level, plans exist for unit outages, during which most of the work orders will be executed. Liberty initially found, however, no practical means to assess progress against the work order plans. Specifically, Hydro reported on the number of work orders closed, but they also explained that anything not closed was unimportant. Liberty received assurances that Hydro examines every unfinished work order for importance, and those that are important are not left open. In other words, any reported level of progress, large or small, is acceptable, by definition. It is impossible for those not directly engaged to judge progress under such a system.
.
Liberty discussed enhanced reporting methods with Hydro management, and agreed upon a new approach for reporting to the Board. First, work orders would no longer comprise the key measure. Annual Work Plan ("AWP") Items would now serve this purpose. These AWPs might correspond to one or more work orders, but are primarily defined as items in the annual work plan, and are considered critical. The second key difference therefore becomes that failure to complete such activities is deemed a problem. A simple comparison of the number of such AWPs completed, compared to the number included in the work plan for any given date, therefore becomes a meaningful performance indicator.

Hydro proposed and Liberty agreed to a second useful indicator for the Board to monitor progress. That indicator consists of a summary-level presentation comparing: (a) AWPs planned for the year, (b) AWPs planned to be complete as of the present date, and (c) AWPs actually complete at the present date. Hydro also agreed to accompany each chart with a brief discussion of any deviations.

Liberty has been reviewing Hydro status reports that address the process of making generating units ready for the winter season. The last status report reviewed before this writing was dated November 14, 2014. That report covers progress through November 8. A November 18, 2014 email update on the status of Holyrood 1 was also reviewed. Performance in executing the maintenance program has been good. Hydro expected that all work would be largely complete by December 1. A summary report on winter readiness filed on December 1 confirmed that work was largely complete with minor exceptions noted.

Hydro completed two annual unit outages (Units 2 and 3) at Holyrood. Annual work plan (AWP) items on those units were over 95 percent, with the balance of plant items over 90 percent complete. The Unit 1 outage was scheduled for completion in early November. All AWP items are complete and the unit is ready for synchronization, but additional testing is required. Liberty observed that Unit 1 has suffered from vibration issues for more than a year, which suggested the potential for balancing challenges to arise during startup. Hydro's December 1 report stated the unit was available for service.

Discussions with Holyrood Plant management reveal no other material risks to readiness. Despite the significant site disruptions to accommodate the new CT, the maintenance season seems to have been successfully undertaken.

In its November 14th report Hydro reported work on its hydro units was on schedule, but work at several units remained open as the December 1 deadline approached. Hydro forecasted completion dates for Paradise River, Upper Salmon, and Granite Canal of November 28, 21, and 28 respectively. Hydro had reported consistently that the work was not substantial and could be accommodated within the plan, although some work items scheduled for earlier completion slipped into November. Hydro's December 1 report confirmed that the hydro units were available for service.

Liberty finds grounds for optimism about winter readiness maintenance at Holyrood and the hydro units. By contrast, however, the CTs at Hardwoods and Stephenville continue to be plagued by problems. A fire resulted in damage and schedule delays at Hardwoods during the summer. A fire shut down Stephenville in November, and Hardwoods was reduced to limited duty while Hydro determined the causes of the Stephenville fire. That problem appears to be have been corrected. Hydro's December 1 report confirmed Stephenville's availability for service. Hardwoods, however experienced a problem with a fuel control valve in late November. It was therefore not available for service on December 1. It did return to service on December 7. The unit again became unavailable on December 12; the date of its expected return to service was unknown at the time of this report. The Stephenville unit then was out of service from December 8 to 9. These types of continuing problems with both existing CTs raise issues about the level of confidence that should be placed on their availability when needed.

Even before the Stephenville fire, progress appeared to be lagging for the CTs. AWP progress was about 75 percent on both units, with only three weeks remaining until the December 1 target. The Stephenville progress earned a rare yellow ranking in Hydro's November 18th progress report. Even so, a second line (coded "green") was added; *i.e.*, "Forecast Completion Status."

The status report does not discuss the fire, but contains a notation that "fire restoration work has begun."

In some respects, Liberty did not find the news of schedule vulnerability at the CTs a surprise. Hydro has long been aware of the issues associated with these machines. It has spent a great deal of time and effort in 2014 (and before) to improve their availability. The recent events at both units do not lend confidence that the availability upgrades can be successful. If both Stephenville and the new CT are unavailable in December, reserves fall to 105 MW, or less than 6 percent (before the in-service date of the new CT). This is the type of circumstance (in the extreme) that should trigger the actions suggested by the above recommendation that Hydro promptly report to the Board any potential change in the outlook for the adequacy of supply, including increases in forecasted peaks or reductions in unit availabilities.

In considering the next steps, the challenge must be viewed from both the short-term and near-term points of view. The next table summarizes the short-term situation.

Chart 2.7: Reserve Scenarios for the 2014-15 Winter

Scenario	Reserves	
	MW	% of Peak
All units available	275	15.5%
Remove new CT	155	8.7%
Remove Existing CTs	105	5.9%

The new CT will not be in service as originally planned (early December) and counting on the availability of the two existing CTs is uncertain. Under this set of assumptions, Hydro entered the winter on December 1 with an uncomfortably low level of reserves, despite the accomplishments of recent months.

c. Capital Projects

The Board annually reviews and approves Hydro's capital plan. Traditionally, Hydro completes less than the planned capital budget. The 2014 plan has special priority because of its potential contribution to availability improvement. Accordingly, Hydro committed to completing the vast majority of the work.

The 2014 budget included 44 generation-related capital projects. Of these, 36 were intended to be complete by year-end. Hydro's November status reports indicate that 33 of the 36 will be completed in 2014. Hydro identified the incomplete projects and none of them are expected to impact reliability.

d. Critical Spares

Liberty has been monitoring Hydro's progress reports addressing efforts to ensure that critical spares remain available. The last status report before this writing was November 14, 2014. It covers progress through November 8. Hydro also filed an updated report on December 9th.

As a part of its master plan for availability improvement, Hydro committed to extensive reviews of the spares inventory at Holyrood, the CTs, and the hydro units. Consultants prepared reports for Holyrood and the CTs; internal resources addressed the hydro units. Hydro took a sophisticated and detailed approach to identify and score parts criticality. Notwithstanding this effort and information, not all identified critical spares were procured by December 1. Work is still ongoing to procure the necessary spares. It therefore is not clear what, if any, availability benefits might result for this winter.

e. Winter Preparedness

Liberty has been monitoring Hydro's reports addressing processes and activities associated with preparing supply resources for readiness to serve during the coming winter period. Much of the preceding discussion of this report chapter concerns readiness of generating units for winter service. Hydro did prepare a specific "master plan," issued on August 29, 2014. Liberty reviewed the plan, monitored progress against it, and reviewed actions with Hydro. The last status report before this writing was October 1, 2014. Hydro filed a summary report on December 1. Liberty found the plan was responsive to the Board's directions and generally consistent with Hydro's needs.

Hydro developed checklists for emergency preparation and response and implemented those checklists in a recent potential weather emergency. The process appears good as does the implementing forms, although the process is a work in progress that is not fully in place.

The same is true for Hydro's self-assessment, which follows a NERC-designed checklist to help gauge how prepared various organizations are. This effort is also a work in progress. It has been used by other organizations, but not universally applied. Liberty would expect the 2014 experience with both the checklists and the self-assessment to result in a more universal application next year with greater overall effectiveness.

f. Asset Management Program

Liberty has examined as part of our current effort the degree to which execution of the program conforms to its scope and design. Many of the subjects addressed in this chapter (*e.g.*, maintenance, capital, spares, and availability improvement) offer direct means of assessing program execution effectiveness. In maintenance, Liberty concluded that the performance of the work at Holyrood was good. It was also good at the hydro units, although considerable work fell into November. Maintenance was behind schedule for the CTs and was further challenged at the CTs by fires at both units and a fuel control valve issue at one unit.

The execution of the capital program for generation was also good, producing a higher project completion rate than normal, with no slippage in reliability-affecting capital projects.

6. Conservation and Demand Management

Newfoundland Power and Hydro offered joint energy efficiency programs ("takeCHARGE" programs) to residential customers using electric heat starting in 2009. These programs include:

- Insulations Rebates for insulating basement walls, basement ceilings, and attic and crawl spaces
- Thermostat Rebates for certain programmable and electronic thermostats
- ENERGY STAR® Windows Rebates for ENERGY STAR® certified windows.

An external consultant evaluated the takeCHARGE programs for Newfoundland Power and Hydro,[5] looking at performance from 2009 through 2012, in order to:

- Assess delivery effectiveness
- Identify any barriers to success and operational effectiveness
- Examine adoption rates and motivations for installing program technologies
- Determine current and remaining program effectiveness
- Identify strategies and performance characteristics that should be considered upon retirement of the programs.

The consultant's study concluded that, overall, the three takeCHARGE programs operated smoothly and cost-effectively, and met or surpassed all 2012 participation and savings goals. Customers had favorable impressions of the program. The study identified several barriers whose removal would have enhanced program execution. The report also recommended a specific set of options for future consideration as follows:

- Existing Homes Market
    - A Whole House Program or Bundling Energy Efficiency Measures to provide a broader approach by taking a whole-house or bundled-measures view, thereby incenting participants to implement all eligible measures
    - Secondary Refrigeration and Freezer Recycling Program to examine whether such units are prevalent enough to incent recycling them
    - Water Saving Measures, such as low-flow shower heads and faucet aerators, to reduce water heater energy consumption
- ENERGY STAR® New Homes Program, recognizing the increase in larger new homes, in order to enhance focus on total home performance. The ENERGY STAR® New Homes program focuses on total home performance, exceeding building code requirements, requiring qualifying appliances, and requiring inspection and certification.
- R2000 Compliant Program, which also establishes high performance criteria and other elements like those incorporated into ENERGY STAR®.

Residential customers on the Island Interconnected System had access to the following conservation and demand management programs in 2013:[6]

- ENERGY STAR® windows, insulation, and thermostats, offered since 2009, with windows and insulation offerings terminated for new builds at the end of 2013. The efficiency standards of updated building codes muted the need for windows and insulation incentives in new builds. The focus going forward will shift to retrofits.
- High Efficiency Heat Recovery Ventilation rebates, begun in the fall of 2013. New and existing homes qualify, regardless of heating source.

Commercial programs available on the Island Interconnected System in 2013 included:

[5] Response to #PUB-NP-163.
[6] Response to #PUB-NLH-436.

- HP T-8 lighting systems
- The Business Efficiency Program, begun in November of 2013, which includes walkthrough audits, technical support, and financial support for feasibility studies and capital retrofits.

Hydro also launched a three-year Industrial Energy Efficiency pilot program in 2010, closing it to new applicants in the fall of 2013.

Newfoundland Power separately addresses peak demand reduction through the Curtailable Service Option and facilities management initiatives (described in Five-Year Energy Conservation Plan Reports to the Board).[7]

Hydro and Newfoundland Power plan to retain a consultant to conduct a study of the current potential for conservation and demand management potential, in order to identify "remaining achievable, cost-effective, electric energy efficiency and demand management potential." The planned study scope includes modeling baseline consumption, identifying technology options, and assessing economical potential for all customer sectors. Hydro anticipates consultant selection by November 2014 and report completion by the end of 2015.[8]

Hydro and Newfoundland Power evaluate energy efficiency programs for the purpose of determining their cost effectiveness. The Companies use a "Total Resource Cost" test as developed by the Public Utility Commission and the Energy Commission of the State of California. The tests undergo annual updates, which Newfoundland Power's annual Conservation and Demand Management reports (filed with the Board) reflect.[9] Hydro reports that it is updating its cost effectiveness model.[10] Hydro plans to retain a consultant in the fall of 2014 to review the marginal study last undertaken by an outside firm in 2006. The Company anticipates that a more comprehensive, 2015 marginal costs analysis will follow this initial review.[11] As the Companies report, the test of effectiveness of their programs is whether energy savings exceed program costs.[12]

Hydro filed its 2013 Conservation and Demand Management Report in April 2014.[13] The report listed the recent-year expenditures shown (in thousands of dollars) and energy savings (shown in MWh) in the next table.

[7] Response to #PUB-NLH-437.
[8] Response to #PUB-NLH-433.
[9] Response to #PUB-NLH-434.
[10] Response to #PUB-NLH-436.
[11] Response to #PUB-NLH-435.
[12] Response to #PUB-NLH-437.
[13] Response to #PUB-NLH-436.

Table 2.8: Hydro's CDM Expenditures and Energy Savings

Thousands of Dollars

	2009	2010	2011	2012	2013
Windows	44	48	80	117	169
Insulation	40	60	140	126	157
Thermostats	13	19	31	47	51
Coupon Program	-	140	135	-	-
Commercial Lighting	13	12	59	20	29
Industrial	57	221	103	173	89
Block Heater Timer	-	-	-	31	8
Isolated Systems Community	-	-	-	858	871
ISBEP	-	-	-	93	115
Heat Recovery Ventilator	-	-	-	-	11
Business Efficiency Program	-	-	-	-	45
Small Technologies	-	-	-	-	1
Total	**167**	**500**	**548**	**1,465**	**1,546**

MWh

	2009	2010	2011	2012	2013
Windows	13	37	61	136	99
Insulation	35	126	404	382	545
Thermostats	9	35	30	53	24
Coupon Program	-	64	256	-	-
Commercial Lighting	3	10	227	95	99
Industrial	-	-	165	3,172	-
Block Heater Timer	-	-	-	-	288
Isolated Systems Community	-	-	-	1,673	1,096
ISBEP	-	-	-	3	26
Heat Recovery Ventilator	-	-	-	-	-
Business Efficiency Program	-	-	-	-	-
Total	**60**	**272**	**1.143**	**5.514**	**2.177**

Hydro and Newfoundland Power provide a range of conservation and demand management education and support activities, spending about $900 thousand in 2012. Plans for the 2012-2016 period call for a one-third increase in annual spending by 2016. The Companies have spent and plan to continue spending about $500 thousand per year in planning costs, which include surveys and research.[14]

D. Conclusions

2.1. Hydro has made major improvements in its load forecasting capabilities as they apply to supply planning. *(Recommendation No. 2.1 and 2.2)*

2.2. Improvements to the short-term operating forecasts have also been made, but have not yet been fully proven. *(Recommendation No. 2.1 and 2.2)*

2.3. Hydro has made significant improvement in relating transmission losses to generation configurations, but has yet to complete the effort. *(Recommendation No. 2.3)*

The guide that Hydro has developed to determine incremental transmission losses from various generation configurations brings a significant improvement in the ability to forecast short-term load accurately.

2.4. Hydro has implemented the change to load reporting on an IIS basis, as recommended.

2.5. Liberty continues to consider the P90 forecast as the preferred planning base. *(Recommendation Nos. 2.4 and 2.5)*

Liberty believes the P90 forecast is the appropriate planning base, but Liberty also recognizes that the key issue is the extent to which decision-makers consider the P90 effect in their deliberations. Hydro's reports in this regard include the P90 case. Hydro and the Board must consider the P90 case in any consideration of supply availability. This transparency of inclusion by Hydro of the P90 case will make use of P50 as the base irrelevant.

[14] Response to #PUB-NLH-437.

2.6. Hydro's conclusion that weather caused actual peak load to exceed the forecasted annual peak forecasted in all four months of the 2013-14 winter warrants further support. *(Recommendation No. 2.6)*

It does not appear that Hydro sought or found the potential "unusual factors" which are of concern but rather concluded that weather was the cause. The data supporting this conclusion is reasonable, but would be more convincing if the specific correlations between the multiple forecast exceedances and the weather conditions on those days were provided.

2.7. Hydro's reconstruction of its peak loads to account for conditions that can make it artificially low is not convincing. *(Recommendation No. 2.6)*

Liberty questions the validity of Hydro's approach, because the load forecasting process on which it relies displayed many anomalies in the 2013-14 winter. The anomalies call into question the estimate's usefulness. It is unclear what, if any conclusion, Hydro has drawn regarding what peak would have been reached in the past winter if the system had been able to continue serving full load.

2.8. Hydro implemented a number of load forecasting process improvements during 2014.

The increased focus on reserve levels, as opposed to a sole focus on LOLH, represents a significant step forward. The consideration of the P90 forecast also comprises an important improvement. Hydro's approach, which involved a degree of "wait and see," in the past did not turn out well between 2012 and 2014. As that recent experience demonstrated, the strategy has significant risks and can get dangerous in a hurry. Given the addition of significant new capacity with Muskrat Falls in the near future there is little need to add new generation now although reserves are still too low. However the strategy must be enhanced vigilance over load growth and unit availability, such that timely action can be taken if current reserves are jeopardized.

2.9. Despite nearly 200 MW of additional generation and demand-side resources, the supply situation is expected to remain tight until the arrival of Muskrat Falls.

2.10. Additional new generation does not present a good option, unless new load materializes or availability declines.

2.11. Despite improvement initiatives in 2014, availability remains a major challenge.

It represents the only remaining, practicable option for improving supply reliability in the near-term. Hydro needs to pursue availability aggressively, in conjunction with exploring demand-side potential.

2.12. The new CT is urgently needed for this winter and must be expedited into service as quickly as possible. (*Recommendation No. 2.10)*

Despite especially strong schedule performance to date (considering the March 2014 initiation of accelerated efforts), Hydro needs to press for the earliest available in-service date. With reserves of only 8.7% in December 2014, the need for the unit remains urgent.

2.13. Securing arrangements for 75 MW (including one for 15 MW in the process of finalization) in recent months reflects a successful effort to secure interruptible load.

2.14. Hydro's application of color coding is not fully meeting the Board's requirements in seeking reports, nor does that application serve to give Hydro management early

warning of matters that may require its intervention. *(Recommendation No. 2.11 and 2.12)*

Liberty believes that this approach to reporting reduces its effectiveness. More significant still is the loss of early management awareness of matters that need attention. In the CT case, the alert was included routinely as one of ten observations, and the other nine were all positive. The approach taken raises the possibility of "December surprises" when the year's performance is finally reconciled.

2.15. Maintenance initiatives during 2014 have been generally successful. *(Recommendation Nos. 2.13 and 2.14)*

2.16. Despite substantial progress in addressing winter readiness, lingering problems with Hydro's existing CTs pose supply adequacy threats this winter. *(Recommendation Nos. 2.13 and 2.14)*

Hardwoods and Stephenville CTs continue to be plagued by problems to the extent that the confidence that they will be there when needed is low. With the winter emerging, little more can be done to reverse Hydro's precarious supply position. Liberty anticipates that the new CT will be expedited to the fullest extent possible by Hydro. Nevertheless, while the new CT is unavailable, Hydro requires a contingency plan to harness every available MW of generation. Should extreme weather arrive while in this vulnerable state, even a partial loss of a big unit threatens emergency conditions.

2.17. Hydro has made progress in completing planned 2014 capital projects at its generating units.

It seems clear that Hydro's current approach to the management of capital projects is bearing fruit. The team demonstrated an awareness and understanding of status and reported progress regularly.

2.18. While progress has been made in assessing parts criticality for generating units, Hydro has yet to complete the procurement of critical spares. *(Recommendation No. 2.15)*

2.19. Hydro has made reasonable progress in structuring and executing a winter readiness plan and should continue to develop its acceptance and use.

Liberty found that the winter readiness effort was strong, and achieved positive results that will contribute to reliability in the coming winter.

2.20. Liberty found field execution of the asset management program in 2014 to be sound, recognizing, however, that uncertainties about certain generating units remain.

2.21. Conservation and Demand Management Programs have focused on cost-effective energy reductions; the focus needs to expand to include demand reductions. *(Recommendation 2.16)*

The focus to date has arisen through a transparent process that appears to have general stakeholder acceptance. Programs have had a reasonably well designed scope, results have been subjected to regular stakeholder scrutiny, and outside experts have reviewed both their design and implementation. Cost-effective savings have been achieved.

Thus, without being critical of efforts that have been undertaken, it is clear that a focus on demand (versus energy) reduction has particular importance. A variety of efforts planned for this upcoming year recognize the need to add that focus. We underscore the importance of promptly and comprehensively pursuing them.

2.22. History suggests that Hydro will consult with Newfoundland Power on the design and results of the coming analyses related to conservation and demand management, but it is not clear that Newfoundland Power will share "ownership" of the process.

Personnel from Newfoundland Power consider Hydro to have been open in discussing planned work, in sharing results, and in addressing use of analytical information in past program design and evaluation. It remains clear, however, that Hydro's system planners retain responsibility for program design, the range of assumptions analyzed, the nature of the analyses, selection of resources to assist in performing analyses, oversight of study and analytical work, and final reports.

The added dimension of demand management this year, and in particular the very high importance that needs to be placed on it, make work this upcoming year different and particularly critical. For example, the range of assumptions made about the Muskrat Falls schedule and costs may have great bearing on what programs make sense from a reliability and cost perspective. The work to be undertaken must proceed with dispatch despite what Liberty would observe to be uncertain estimates of project schedule and cost. Liberty does not make this observation on the basis of examination of actual plans or progress, but on the basis of what decades of experience says about megaprojects in the utility industry.

The particular importance of supply considerations over the next few years, as they relate to demand management, centers upon the question of pay-back periods for potential demand-side options. A program designed to reduce demand may not look effective if one assumes that Muskrat Falls and the link to the Island Interconnected System arrive as scheduled. The question in that event becomes how long a delay it would take to make a program a net effective contributor to supply adequacy. Clearly, a meaningful answer to that question requires a robust range of potential in-service dates for new capacity.

For the longer term, even if reserve adequacy questions are mooted for an extended period, analysis of demand management programs require a sound set of assumptions about what costs to customers who pay for electricity will be avoided for each block of capability that is avoided. It would appear that such an analysis requires at least two key inputs: (a) thorough knowledge about the contract structure that determines what costs and benefits will come to customers paying for demand management in utility rates, and (b) what range of cost estimates for new capacity should be used to apply that structure in calculating those costs and benefits.

One can conclude that it is not necessarily certain that Hydro and Newfoundland Power (and perhaps other stakeholders as well) will agree on the range of schedule and cost assumptions that should be employed. Scope and methodological viewpoints may differ as well. The same is true of views about the time required to complete work that must serve as the foundation for assessing conservation and demand management potential. Full visibility into study work and management of those performing it and vetting results also has importance in our view. Therefore, while Liberty commends efforts to engage Newfoundland Power in discussions and while Liberty would expect Hydro to consider to listen carefully and respond to input, a better approach would be to approach the work not from the perspective of "ownership" by Hydro, but of "partnership" between the two and transparency of the work and its results to the Board and to all stakeholders.

E. Recommendations

2.1. **Provide the Board with monthly updates on the status of Nostradamus upgrades until the production model is fully in-service and shaken down.** *(Conclusion No. 2.1 and 2.2)*

2.2. **By April 30, 2015, provide the Board an assessment of the effectiveness of Nostradamus during the 2014-15 winter and the sufficiency of the model for continued future use.** *(Conclusion No. 2.1 and 2.2)*

2.3. **Provide the Board with the guide on system losses under various configurations and any instructions for their use.** *(Conclusion No. 2.3)*

2.4. **Continue to include the P90 load forecast prominently in all evaluations of power supply adequacy.** *(Conclusion No. 2.5)*

2.5. **By March 1, 2015, provide data relating the actual values of the weather variable on the 2013-14 winter days on which the annual peak forecast was exceeded.** *(Conclusion No. 2.5)*

2.6. **By March 1, 2015: (1) clarify Hydro's proposed reconstruction of the winter 2013-14 peak, (2) provide a specific value for the reconstructed peak, and (3) report on the impact of the reconstructed peak on the analysis of 2013-14 forecast exceedances.** *(Conclusion Nos. 2.6 and 2.7)*

2.7. **Validate a reasonable and practical criterion for reserve margins, although not necessarily in the form of a rigid number, and characterize the degree of risk associated with that criterion.**

2.8. **Report quarterly on the rolling 12-month performance of its units, including actual forced outage rates and their relation to: (a) past historical rates, and (b) the assumptions used in the LOLH calculations.**

2.9. **Report promptly to the Board any potential change in the outlook for the adequacy of supply, including increases in forecasted peaks or reductions in unit availabilities.**

With respect to the last recommendation, Liberty notes increasing concerns with the continuing CT availability issues at Hardwoods and Stephenville. Hydro needs to continue to keep the Board informed about causes and solutions for lingering uncertainties about the status of such facilities.

2.10. **Continue to treat completion of the new CT as soon as possible a high priority for Hydro management, supported by close executive attention.** (*Conclusion No. 2.12)*

2.11. Establish and use a more effective system of reporting and analyzing status to give Hydro management early warning and the opportunity for intervention. *(Conclusion No. 2.14)*

2.12. In all reports to the Board, provide, and adhere to, a clear definition of reporting practices, including the definition of classifications (such as colors) used to categorize performance status. *(Conclusion No. 2.14)*

2.13. Given the vulnerabilities likely to be present on December 1, 2014, Hydro must take at least the following actions immediately:

- **a) Prepare an emergency contingency plan to identify all generation resources for a potential supply emergency while the new CT remains unavailable.**
- **b) Report to the Board all steps being taken to expedite completion of the new CT.**
- **c) Be prepared to trigger emergency plans when and if extreme weather sufficient to reach or exceed expected peaks is forecast.**
- **d) Report to the Board daily whenever forecasted reserves for the day are less than 10 percent.**
- **e) Report to the Board immediately whenever forecast reserves fall under 10 percent during any day.** *(Conclusion No. 2.15 and 2.16)*

For the longer term, the new CT will add additional capacity. The same may not be true for the existence of CTs at Hardwoods and Stephenville. The next table summarizes the reserve situation for scenarios if these units are eliminated from consideration.

Chart 2.9: Reserve Scenarios for the 2017-18 Winter

Scenario	Reserves	
	MW	% of Peak
All units available	239	13.2%
Remove Hardwoods	189	10.4%
Remove Stephenville	139	7.7%

Should a determination be made that both Hardwoods and Stephenville are too unreliable to count on for supply planning purposes, then new generation is required. The procurement process for that new generation would have to start immediately, because reserve margins next winter (2015-16) will be less than 9 percent. The next table depicts those margins.

Chart 2.10: Reserves without the Old CTs

Winter	MW	% of Peak
2015-16	160	8.9%
2016-17	141	7.8%
2017-18	139	7.7%

Liberty considers concerns about the vulnerability of the existing CTs at Hardwoods and Stephenville to represent a real problem. Despite that conclusion, however, it is not appropriate to assign a 0 percent availability factor to them for planning purposes. Forced outage rates have been high, but not enough to discount the units entirely. Second, such an assumption would require an immediate new procurement of generation, a costly proposition that may have limited value once Muskrat Falls is in service. Third, considerable investments have recently been made on these machines, and reliance on their continued reliability may be possible.

2.14. Continue to rely on the old CTs for reliable capacity and continue to focus on steps to improve their availability. *(Conclusion No. 2.15 and 2.16)*

2.15. Report to the Board by February 15, 2015, the final status of the program for critical spares, its results versus expectations of the master plan, a listing of spares to be procured, and when they will be available. *(Conclusion No. 2.18)*

2.16. Complete planned demand management analysis on a Hydro/Newfoundland Power jointly scoped, conducted, and developed basis and report to the Board a structured cost/benefit analysis of short term program alternatives by September 15, 2015. *(Conclusion No. 2.21)*

The most essential elements of this recommendation are:

- Ensuring, in the event that Hydro and Newfoundland Power do not agree on a range of new capacity timing and cost assumptions to consider, that the work planned incorporates a range of assumptions that is sufficiently broad to encompass those of both entities.
- Ensuring methods and perspectives broad enough to provide for a full identification and analysis of the short-term costs and benefits (both economic and with respect to improving reserves) of options for the period leading up to the introduction of Muskrat Falls
- Shortening what we understand to be Hydro's estimation of the time for completing required foundational work and generating a list and a structured evaluation of potential demand side options for the short term.
- Making the study and analytical process and its resulting options and the analysis of them transparent and available to the Board and stakeholders as soon as possible, in order to expedite the process of instituting any short term demand side options that may prove beneficial.
- With respect to longer term options, ensuring that work now proceeds with as clear an understanding as possible of the costs avoided by and the benefits made available to customers who bear responsibility for new capacity costs and the costs of conservation and demand management costs, in order to provide a sound foundation for determining what measures and programs should be instituted.

III. Asset Management Programmatic Aspects

A. Background

Effective asset management seeks to prevent equipment-caused customer interruptions by employing cost-effective inspection, maintenance, and rehabilitation practices. Effective programs and practices require a design and funding sufficient to provide sound practices executed on appropriate cycles through skilled resources and equipment, all operating in accord with suitable goals, strategies, targets, and performance measurement. Hydro's Generation and Transmission and Rural Operations ("TRO") divisions have responsibility for the management of their assets, with substantial support from Nalcor's Project Execution and Technical Services organization.

Liberty reviewed Hydro's asset management strategies and activities, including equipment inspection, repair, replacement, upgrading, maintenance and rehabilitation policies, program requirements and actual practices, and the adequacy of its strategies and compliance with them. Our review included the organizations responsible for asset management operations, accountability for work completion, staffing levels, training, succession planning, and the maintenance management tracking methods used to execute asset management strategies and meet goals and targets fully and efficiently.

B. Chapter Summary

Hydro characterizes the foundational element of asset management strategy as:

- Knowing the condition of critical assets
- Understanding how those assets are performing
- Maintaining, renewing, or replacing critical assets to prevent their unexpected failure.

Hydro executes asset management strategies pursuant to annual work plans. It does so under well-organized and defined command, control, and monitoring responsibilities and methods for planning, managing, scheduling, and executing work activities.

Hydro's asset management program has been in continuous evolution since about 2006 and has many attributes that are "best practices," including:

- Councils of experts
- The stage gate approach
- The Execution Work Plan program and work execution managers
- A heavy focus on condition assessments of assets and their link to the plan
- 1-5-20 year planning
- Continuing improvement and evolution, consistent with the guiding framework.

Liberty has concluded that Hydro has an appropriate approach to asset management with its program sound in scope and design. However, the program did not reflect appropriately the age and condition of Hydro's assets. This issue and others concerning implementation are addressed in Chapters II and V.

C. Findings

1. Asset Management Mission, Organization, and Resources

a. Hydro Asset Management's Vision and Purpose

Nalcor's vision of Asset Management, which it defines in reasonably typical, life-cycle form, is:[15]

> *the comprehensive management of asset requirements, planning, procurement, operations, maintenance, and evaluation in terms of life extension or rehabilitation, and equipment replacement or retirement as necessary to achieve maximum value for the stakeholders based on the required standard of service to current and future generations.*

The asset management process consists of long-term planning, short-term work planning and scheduling, work execution, and operations. Nalcor's standardized asset management system applies to Hydro's assets. The management of these assets follows a process of determining service levels, acquiring and renewing assets, operating those assets, and maintaining them.

Nalcor has adopted an enterprise-wide (*i.e.*, including Hydro) plan on the premise that it can achieve significant organizational synergies through the use of a common framework, consistent organization structures, and key position definitions. Aspects deemed critical in making asset management effective include: (a) knowing the condition of critical assets, (b) understanding how they are performing, and (c) maintaining, renewing, or replacing those to minimize the risk of unexpected failure.

b. Asset Management Process Maturation

A reorganization of asset management in 2010 sought to improve: (a) accountability and performance expectations, (b) consistency of approaches to maintenance, renewal, and replacement, and (c) approaches to justifying capital and operating budgets and supporting resources. Initiatives undertaken in 2010 focused on ensuring work tracking against plans and identification of needed recovery or acceleration initiatives.[16]

Work proceeds under an annual work plan, to which these targets and expectations relate. Liberty found these plans to be comprehensive. Hydro has also demonstrated flexibility in adjusting them to changing circumstances. For example,[17] Hydro made changes to the 2014 work plan to address action items arising from the January 2014 outage events:

- Additional oversight of annual work plans to enhance work completion
- Inclusion of maintenance compliance targets in performance agreements with managers
- Institution of maintenance backlog reviews bi-weekly, particularly emphasizing terminal station and breaker targets, supported by graphic reporting of completion progress
- Improving coordination between Project Execution and Technical Services Planning and Scheduling and regional resources, including preparation of an integrated resource plan to

[15] Response to RFI #PUB-NLH-342.
[16] Response to RFI #PUB-NLH-349.
[17] Responses to RFIs #PUB-NLH-155 and 367.

identify resource shortfalls and to maximize use of employees and contractors to complete planned work

- Identifying and filling resource needs for addressing maintenance backlogs, including increased use of contractors, pooling resources from other regions and additional temporary employees.

c. The Nalcor-Led Asset Management Organization

Nalcor management personnel guide the provision of some of Hydro's asset management functions.[18] Nalcor employees occupy the top level positions in the combined organizational approach to asset management, which includes three main groups.

First, the Office of Asset Management works with senior leadership and operation managers to establish common standards and practices, and to coordinate capital-planning activities across Nalcor. A Nalcor Manager, Office of Asset Management, reporting to Nalcor's Vice President of Project Execution and Technical Services ("PETs") heads the Office of Asset Management.

Second, the Nalcor Project Execution function serves a project management role. A Manager-Project Execution Regulated, employs a Hydro team for capital projects and some O&M programs. Project Execution teams coordinate internal and external resources. They perform reporting, cost monitoring and reporting, project planning, risk assessment and management, change management, coordination reviews, contract preparation and management, project documentation, and day-to-day project management.

Third, Nalcor's Technical Services functions house the functional experts required to provide engineering and technical support. They work with the project management teams that operate in the Project Execution function. They provide project design services, engineering studies, site investigations, technical investigations, development of engineering standards, operations technical support, preparation of capital budgets, and project cost estimates.

A Nalcor Manager, Engineering and Project Support, directs the activities of a number of engineers and technologists, some of which are dedicated solely or primarily to Hydro and some of which are similarly assigned to Nalcor. This "home base" assignment follows expectations about the entity for which employees will dedicate a majority of their time. In essence, home basing at Nalcor means an expectation that the majority of an employee's time will be spent on non-Hydro work. Chapter X of this report (*Governance and Staffing*) discusses home basing and resource sharing more extensively.

Four Nalcor Manager, Engineering, positions provide direction for the engineering disciplines of electrical, mechanical, civil, and protection, control, and communications. These managers also direct employees home based either in Hydro or Nalcor (or non-Hydro), based on the expected benefitting entity of the majority of their work. Generally, Hydro serves as the home base for most of these employees, some of whom work nearly, if not totally, exclusively on Hydro assignments.

[18] Response to RFI #PUB-NLH-343.

d. The Hydro Asset Management Organization

The immediately preceding sub-section addressed the Nalcor-led elements of the asset management organization. A majority of that organization's resources, while operating under Nalcor supervision, nevertheless dedicate most or essentially all of their time to Hydro work. The asset management functions of personnel employed and managed directly by Hydro executive management are described for TRO in Chapter V.

2. Generation and Transmission and Rural Operations Asset Management

Liberty's investigation regarding Hydro's asset management of its generation assets is described in detail in Chapter II Planning and Supply. Liberty reviewed Hydro's 2014 capital projects, its 2014 maintenance plan for generation units to ensure their availability for the winter season and its project on critical spares for generating units. Conclusions and recommendations relating to asset management of generating assets are in that chapter.

Chapter V describes Liberty's investigation and conclusions regarding the management of assets in Hydro's Transmission and Rural Operations division and sets out detailed conclusions and recommendations.

D. Conclusions

3.1. The design and scope of Hydro's asset management program is sound and conforms to best practices.

Hydro's execution of asset management activities, however, raises issues that other chapters of this report address.

E. Recommendations

Recommendations relating to execution of asset management activities are set out in Chapters II and V.

IV. Transmission and Distribution System Planning and Design

A. Background

Liberty examined Hydro's transmission and distributions systems, including the planning for, design of and the reliability performance of the systems as part of the work for this report on the Island Interconnected System's ability to meet customers' load requirements up to the interconnection with Muskrat Falls.

Hydro owns and operates 56 transmission circuits (lines), 52 transmission terminal stations (there are five additional customer-owned terminal stations), 35 distribution substations (or 52 when including terminal stations that also employ transformers serving the distribution system), and 79 distribution feeders. Hydro[19] directly serves 5 industrial customers over its transmission system, and 2,971 commercial customers and 19,763 rural residential customers in the Central and Great Northern Peninsula (GNP) portions of Newfoundland over its distribution system. Hydro serves as the source of the bulk power for about 93 percent of electric energy and demand required for Newfoundland Power's 256,000 customers.

1. Reliability

Liberty's examination of planning and design emphasized how reliability issues affect how Hydro identifies and proceeds to meet current and future system needs. Liberty therefore began with a review of recent-year reliability metrics for Hydro's transmission and distribution systems, in order to determine their base levels of performance and to identify the impacts that major events in recent years have had on that performance. This baseline review also sought to disclose any particular areas of concern or emphasis for Liberty's review of transmission and distribution management and operations, which fall under Hydro's Transmission and Rural Operations (TRO) group.

Electric utilities generally measure reliability in several ways, which include:

- The number of customer interruptions (CIs)
- The number of customer minutes of interruptions (CMIs)
- The system average interruption duration index (SAIDI)
- The system average interruption frequency index (SAIFI).

Utilities generally take such measures both with and without major events. Excluding the effects of those events helps to minimize distortion in making comparisons among results across a period of years.

2. Planning

Transmission and Distribution (T&D) Systems Planning activities identify and plan to fill needs for capital transmission, substation, and distribution projects required to provide the capacity to accommodate load growth and stability and to maintain system condition and reliability at acceptable levels. Planning duties include conducting load flow and other studies, developing

[19] Response to RFI #PUB-NLH-308.

energy and peak demand forecasts for business and technical reasons, and assisting system operators in addressing real-time system operations issues.

Liberty reviewed Hydro's planning organization, its criteria for planning capacity and reliability projects, and its provision of support for Energy Control Center activities.

3. Design

Hydro defines its transmission system as voltage electrical equipment having a voltage rating equal to or greater than 66 kV. The distribution systems include electrical equipment having a voltage rating less than or equal to 46 kV. Liberty's review of planning addressed: (a) the age of Hydro's T&D equipment, (b) the appropriateness of the design and construction considerations applied to its electric systems, (c) how Hydro applies sectionalizing, (d) Supervisory Control and Data Acquisition ("SCADA"), and (e) overvoltage and animal protection. Liberty examined whether Hydro's design practices conform to the needs of its customers and good utility practices.

4. Protection and Control (P&C)

Protective relays quickly trip circuit breakers to clear line, bus, and transformer faults, in order to minimize equipment damage and to maintain system stability. Utility transmission systems typically use sophisticated impedance-type distance measuring relay schemes. They supplement them with backup secondary relay schemes to allow tripping following primary relaying or circuit breaker malfunction. Utility distribution systems typically use overcurrent relays or electronic reclosers to protect distribution-voltage equipment and feeders. Single-function electromechanical impedance and overcurrent relays have been used for about 90 years. They sometimes prove inaccurate and they require periodic testing to verify operation. Replacing electromechanical transmission relays with electronic relays has become increasingly common in recent decades. The use of programmable multifunction relays reflects the most recent trend. These relays offer high accuracy, do not require much testing, and provide relay status and fault current data. They can also provide breaker control via a SCADA system.

The recommendations made in Liberty's and the Board's 2014 interim reports on Hydro's Protection and Control system and practices, along with other actions identified by Hydro, were combined into the 2014 Integrated Action Plan. Liberty has monitored the progress Hydro made in implementing the actions listed in this Plan on its protective relay scheme design, its Protection and Control organization, its maintenance practices for its electromechanical relays, investigations of relay malfunctions, and the extent it has been modernizing its obsolete relays with programmable relays. Liberty undertook this last task through review of Hydro progress reports and discussion with management. Liberty did not validate progress through field inspection.

B. Chapter Summary

1. Reliability

Industry-standard reliability metrics indicate that transmission and distribution systems on the Island Interconnected System (IIS) generally performed slightly worse in 2013 than in 2009. If the major events of 2011 and 2013 are excluded Hydro's performance using the typically used reliability metrics was generally consistent with Canadian Electricity Association comparators for 2009 through 2013 for distribution and below for transmission. The major generation and transmission events of January 2014 will have an even greater impact on Hydro's 2014 reliability indices when measured after the close of this year. Major system events in 2011 and 2013 caused elevated SAIFI and SAIDI (decreased reliability) for the Hydro's Northern Region and Central Region transmission and distribution systems on the IIS.

Hydro's Northern Region Forced Outage T-SAIDI and its Newfoundland Power Interconnection Forced Outage T-SAIDI were greater at the end of 2013 than they were in 2009 and 2010. Hydro's Central-Rural Region Forced Outage T-SAIDI remained about the same from 2010 to 2013. Hydro's average Central-Rural transmission system Forced Outage T-SAIFI and T-SAIDI were more or less consistent with CEA averages. However, the numbers of T-SAIDI hours resulting from planned outages ran about twice the T-SAIDI hours resulting from forced outages. High outage rates for planned work suggest the potential for reducing the impact on customers and T-SAIDI when work is being performed on the radial 66 kV and 138 kV transmission lines.

Liberty's review of distribution reliability index metrics disclosed that the Northern Region's Distribution Forced SAIDI, excluding major events, was about 37 percent greater in 2013 than it was in 2009. The Central Region's Distribution Forced SAIDI roughly doubled over this period. Excluding major events makes the Central Region Forced Outage SAIFI and SAIDI generally consistent with CEA average indices. What distinguishes the region is the large number of SAIDI hours resulting from planned outages (about twice the number resulting from forced outages). Hydro has experienced comparatively high numbers of Planned Outage SAIDI hours. It must do so because the long distances between feeders precludes the ability to transfer loads among distribution feeders when repairing and upgrading substation and distribution feeders.

Following the review of Hydro's reliability performance, Liberty concluded that:

- Customers on the IIS experienced a greater number of lengthy interruptions because of planned transmission outages than because of forced outages
- Transmission-forced outage frequencies and durations both increased from 2009 to 2013
- Distribution outage frequencies and durations have increased, but remain consistent with Canadian averages after adjustment for major events
- Loss of supply and scheduled outages have been the largest contributors to outages.

Liberty makes a number of recommendations to enhance reliability performance.

2. Planning

Hydro transmission and distribution planning groups conduct capacity planning under criteria that conform to good utility practices. Their conduct of load flow, stability, voltage, and short circuit studies for transmission and distribution systems also conform to good utility practices. Their work has led Hydro to conclude that no transmission circuit, terminal station transformer, distribution transformer, or feeder will be overloaded when the 2014/2015 winter peak occurs.

3. Design

Hydro generally employs redundant 230 kV circuits to support reliability when one is out. By contrast, many of its 138 kV circuits, especially on the Great Northern Peninsula (where salt contamination is an issue), and nearly all of its 66/69 kV circuits operate radially. The lack of a backup source in this configuration exposes Hydro's customers to interruptions of long durations when sustained line faults occur, or whenever Hydro performs maintenance on the circuits. We do not consider looping these radial 138 kV and 66/69 kV circuits likely in the near term, because of the large capital expenditures required.

One matter of concern to Liberty arises from the choice by Hydro not to provide a spare 125 MVA 230/138 kV transformer for the two 138 kV loops that operate as part of its transmission system. Hydro had relied on the N-1 transformer contingency designed into these loops to prevent operating problems resulting from failure of a transformer. The January 2014 events witnessed the loss of one transformer in each of these loops, which eliminated the backup provided by N-1 transformer contingency for at least the Stony Brook to Sunnyside 138 kV loop. The age and possible condition issues involving Hydro's aged 125 MVA transformers makes the lack of a spare transformer unnecessarily risky in our view.

Hydro uses downstream feeder reclosers to improve feeder performance. Liberty has a number of concerns about the conformity of feeder design with good utility practices. First, Hydro has not fully implemented SCADA control and monitoring of all terminal stations and distribution substations. Second, Hydro has not yet fully updated its Geographic Information System (GIS). Third, it has not been applying animal guards at distribution substations. Hydro has work underway to update its GIS system, but does not plan to add more terminal stations or substations to its SCADA system.

4. Protection and Control

The Interim Report sets forth Liberty's view that transmission outages of January 2014 arose in part due to inadequacy of the breaker failure relay scheme at Sunnyside Terminal Station and slow tripping of some old air-blast circuit breakers and made a number of recommendations to address these issues. The Board, in its Interim Report, also directed Hydro to undertake actions on these issues. Hydro has been proceeding since to complete the identified actions and address those and other protective relay issues. Several relay protection studies undertaken by Hydro since 2010 identify those issues. The Board, in its Interim Report, directed Hydro to review and report on these earlier studies and recommendations. Hydro had been modernizing its legacy relays and relay schemes over the years. It accelerated in 2014 its pace in modernizing relays, improving relay schemes, and resetting relays, based on those past protective relay studies.

The Protection and Control Department has appropriate staffing, consisting of Electrical Engineers and Engineering Technologists. The group designs, commissions, and maintains Hydro's protective relay and control equipment. The group does the same for other metering, fault recording, and alarm equipment. They also conduct power transformers and circuit breaker testing. The Engineering Technologists use modern relay test equipment to test relays on six-year cycles, which conforms to industry practice. There have been small backlogs in addressing protective relay preventive and corrective maintenance, but Hydro will eliminate them by the end of 2014, based on its current reported pace.

C. Findings

1. Reliability - Performance Metrics

a. Transmission

Hydro[20] tracks the performance of its transmission system using measures of outage frequency and duration:

- For frequency, Transmission Average Interruption Index (T-SAIFI)
- For duration, System Average Interruption Duration Index (T-SAIDI), measured in minutes.

Hydro separately tracks these measures with and without including the impacts of major system events. Hours of customer interruptions due to planned transmission outages have exceeded those caused by forced outages.

Hydro measures transmission reliability using metrics consistent with CEA Bulk Electricity System guidelines. It uses T-SAIFI to measure its number of transmission system forced or planned interruptions by capturing average sustained interruptions per delivery point per year. It uses T-SAIDI to measure the effect of transmission outages on customers by capturing minutes of interruption duration per customer per year.

CEA defines a "major event" as: (1) significant overall transmission system disturbances of at least one minute and including loss of system stability, cascading outages, and abnormal frequency or voltage, or (2) transmission-caused distribution system interruptions of at least 1,000 MW-minutes. Including major events in the measurements does indicate overall performance, but occasional events can distort the evaluation of the effects of transmission system improvements on year-to-year reliability trending. Therefore, excluding major events offers a better means for evaluating reliability improvement measures.

Liberty reviewed Hydro's forced and planned outage-caused T-SAIFI and T-SAIFI average indices for the years 2009 through 2013. Liberty examined trends in these metrics since 2009, both including and excluding major events. Liberty reviewed the performances of Hydro's two IIS transmission regions (Northern and Central-Rural). Liberty also examined the frequency and duration effects that outages on Hydro's transmission system had on the interconnections serving Newfoundland Power. Liberty also reviewed how Hydro's Regions compared to CEA average

[20] Response to RFI #PUB-NLH-339.

T-SAIFI and T-SAIDI, including major events. CEA does not report data that excludes major events.

Comparing Hydro's T-SAIFI and T-SAIDI with averages for utilities across Canada has value, but one must consider the differences in Canadian transmission systems. Transmission systems across Canada are generally connected and they include systems serving major cities through underground systems or employing grids that provide redundant transmission circuits. Hydro's IIS transmission grid, however, contains a number of single radial transmission lines. Hydro's 138 kV and 66/69 kV lines on the Northern Region's Great Northern Peninsula (GNP), supplying multiple delivery points, provides an example. This configuration causes more transmission delivery points to be interrupted following a single transmission line disturbance. For the same reason one would expect better transmission reliability performance for Hydro's interconnections with Newfoundland Power and service to Hydro's industrial customers, who benefit from multiple transmission connections.

Liberty examined Hydro's Northern, Central-Rural, and Newfoundland Power Interconnections T-SAIFI and T-SAIDI data for 2009 through 2013, and tabulated the metrics as averages for the entire five years. We also separately excluded the two atypical years (2011 and 2013).

For the five-year averages, the Central-Rural Forced Outage, T-SAIFI, including all major events, has been close to the CEA average, but the Northern Region has been far in excess of the CEA average. Excluding major events and excluding 2011 and 2013, the Northern Region's Forced Outage T-SAIFI, although much reduced, is still substantially in excess of the CEA average. Hydro's Forced Outage T-SAIFI performance for the Newfoundland Power interconnections appears to be reasonable. Hydro's T-SAIFI for its planned outages is much higher than the CEA average, which can be expected to maintain Hydro's aged transmission system.

For the five-year averages, the Central-Rural Forced Outage, T-SAIDI, including all major events, has been close to the CEA average and has been better when major events are excluded. Northern Region's Forced Outage T-SAIDI was much higher than the corresponding metric for the Central-Rural Region and the Canadian average. However, excluding data from the years 2011 and 2013 makes the Northern Region's average Forced Outage T-SAIDI better than the Canadian average T-SAIDI for 2009, 2010, and 2012. Hydro's Forced Outage T-SAIDI performance for the Newfoundland Power interconnections was much better than the CEA averages excluding 2011 and 2013 data. However, Hydro's T-SAIDIs for planned outages for both Regions far exceeded average. They in fact equaled or exceeded the Forced Outage SAIDIs.

When Liberty examined year-to-year T-SAIFI and T-SAIDI during years 2009 through 2013 Liberty found that forced outage and planned outage T-SAIFI were generally higher in 2013 than they were in 2009. The exception was that the Planned Outage T-SAIFI for the Newfoundland Power Interconnections was the same in 2013 as in 2009. The following paragraphs discuss yearly Forced and Planned T-SAIFI and T-SAIDI, excluding major events.

Forced Outage T-SAIFI for the Northern Region was higher in 2013 than it was in 2009. It went from about 1.2 interruptions in 2009 to 4.1 in 2010, to 6.6 in 2011, to 2.5 in 2012, and to about

2.3 interruptions in 2013. Forced Outage T-SAIFI for the Central-Rural Region was higher in 2013 that it was in 2009. It went from 0.1 interruptions in 2009 to 0.7 in 2010 and 2011, to 1.7 in 2012, and to about 0.4 interruptions in 2013. Forced Outage T-SAIFI for its Newfoundland Power Interconnections was slightly higher in 2013 than in 2009. It went from about 0.1 interruptions in 2009 to 0.5 in 2010, to 0.4 in 2011, to about 0.2 interruptions in 2012 and 2013.

Planned Outage T-SAIFI for the Northern Region was higher in 2013 than it was in 2009. It went from about 1.4 interruptions in 2009 to 1.1 in 2010, to 2.6 in 2011, to 1.4 in 2012, to about 1.9 interruptions in 2013. Planned Outage T-SAIFI for the Central-Rural Region was higher in 2013 than it was in 2009. It went from 0.6 interruptions in 2009 to 1.9 in 2010, to 1.6 in 2011, to 0.6 in 2012, and to about 1.6 interruptions in 2013. Planned Outage T-SAIFI for the Newfoundland Power Interconnections was the same in 2013 as it was in 2009. It went from 0.2 interruptions in 2009 to 0.6 in 2010, to 0.3 in 2011, to about 0.2 interruptions in 2012 and 2013,

Forced Outage T-SAIDI for the Northern Region was much higher in 2013 than it was in 2009. It went from about 43 minutes in 2009 to 9.6 minutes in 2010, to 308 minutes in 2011, to 108 minutes in 2012, and to about 74 minutes in 2013. Forced Outage T-SAIDI for the Central-Rural Region was higher in 2013 than it was in 2009, but was somewhat stable from 2010 to 2013. It went from 0.1 minute in 2009 to 52 minutes in 2010, to 21 minutes in 2011, to 53 minutes in 2012, and to about 55 minutes in 2013. Forced Outage T-SAIDI for the Newfoundland Power Interconnections increased from 2009 to 2013, but it was not elevated between 2010 and 2012. It went from about 2.7 minutes in 2009 to 10.4 minutes in 2010, to 6.9 minutes in 2011, to 9.3 minutes in 2012, and to about 31 minutes in 2013,

Planned Outage T-SAIDI for the Northern Region increased between 2009 and 2012 and decreased in 2013. It went from about 197 minutes in 2009 to 148 minutes in 2010, to 536 minutes in 2011, to 404 minutes in 2012, and to about 319 minutes in 2013. Planned Outage T-SAIDI for the Central-Rural Region increased between 2009 and 2013. It went from 156 minutes in 2009 to 350 minutes in 2010, to 360 minutes in 2011, to 159 minutes in 2012, and to about 370 minutes in 2013. Planned Outage T-SAIDI for the Newfoundland Power Interconnections was higher in 2013 than in 2009, but was low in 2011 and 2012. It went from about 31 minutes in 2009 to 55 minutes in 2010, to 16 minutes in 2011, to 12 minutes in 2012, and to about 44 minutes in 2013.

Hydro's forced transmission outage contribution to Newfoundland Power's SAIDI was low for 2009, 2010, and 2012 (less than 10 minutes not including major events and less than 23 minutes including major events). Hydro's January 2013 major outage events increased Hydro's Newfoundland Power T-SAIDI for 2013. Hydro's planned outage work contributed more to Hydro's Newfoundland Power's SAIDI than did forced outages.

b. Distribution

Hydro uses SAIFI and SAIDI to measure the performance of its distribution system, as utilities commonly do. Liberty reviewed Hydro's Distribution Central Region and Northern Region Forced Outage and Planned Outage SAIFI and SAIDI, both including and excluding major events, across the 2009 through 2013 time period. Liberty did not use measurements for Hydro's system as a whole, which include Labrador and independent distribution systems. Liberty made comparisons to CEA average SAIFI and SAIDI including major events. The Association does not report data excluding major events.

On average, over the five years 2009 through 2013, Hydro's Central Region's Forced Outage SAIFIs, both including and excluding major events, were better than the Canadian average SAIFI. Northern Region's Forced Outage SAIFI exceeded the Canadian average when including major events and for all five years. Excluding the atypical years 2011 and 2013 causes Northern Region's SAIFI to approach the Canadian average. Hydro's SAIFI for its planned outages is higher than the Canadian average.

On average, over the five years 2009 through 2013, SAIDI for both Hydro regions exceeded the Canadian average. However, excluding major events or excluding the 2011 and 2013 data makes both regions' SAIDI better than the Canadian average. Hydro's SAIDI for its planned outages is higher than the CEA average.

When Liberty examined year-to-year Distribution SAIFI and SAIDI for each of the years 2009 through 2013, Liberty found that forced outage and planned outage SAIFI were generally higher in 2013 than in 2009. The exception was Central Region SAIDI for Planned Outages. The following points indicate yearly Forced and Planned SAIFI and SAIDI, excluding major events, as the next paragraphs discuss.

Forced Outage SAIFI for the Northern Region was slightly higher in 2013 than in 2009. It went from about 2.1 interruptions in 2009 to 1.8 in 2010, to 1.6 in 2011, to 2.7 in 2012, and to about 2.2 interruptions in 2013. Forced Outage SAIFI for the Central Region was slightly higher in 2013 than in 2009. It went from 2.0 interruptions in 2009 to 1.1 in 2010, to 1.2 in 2011, to 0.9 in 2012, and to about 2.5 interruptions in 2013.

Planned Outage SAIFI for the Northern Region was slightly higher in 2013 than in 2009. It went from about 2.0 interruptions in 2009 to 1.8 in 2010, to 1.6 in 2011, to 2.7 in 2012, to about 2.2 interruptions in 2013. Planned Outage SAIFI for the Central Region was slightly higher in 2013 than in 2009. It went from about 2.0 interruptions in 2009 to 1.1 in 2010, to 1.2 in 2011, to 0.9 in 2012, and to about 2.5 interruptions in 2013.

Forced Outage SAIDI for the Northern Region was higher in 2013 than in 2009. It went from about 2.8 hours in 2009 to 2.1 hours in 2010, to 5.3 hours in 2011, and to 3.5 hours in 2012, and to about 3.8 hours in 2013. Forced Outage SAIDI for the Central Region was much higher in 2013 than in 2009. It went from about 3.1 hours in 2009 to 3.2 hours in 2010, to 0.8 hours in 2011, to 1.4 hours in 2012, and to about 6.7 hours in 2013. Severe weather in November 2013 caused a 67 hour outage on the Bottom Waters distribution system which contributed to the high SAIDI that year.

Planned Outage SAIDI for the Northern Region was higher in 2013 than in 2009. It went from about 1 hour in 2009 to 0.9 hours in 2010, to 3.2 hours in 2011, to 3.5 hours in 2012, and to about 2.6 hours in 2013. Planned Outage SAIDI for the Central Region was lower in 2013 than in 2009. It went from about 2.9 hours in 2009 to 0.7 hours in 2010 and 2011, to 1.5 hours in 2012, and to 0.2 hours in 2013.

c. Primary Causes of Hydro Customer Interruptions

The following table[21] indicates the numbers and hours of unplanned transmission line outages on Hydro's transmission system for 2004 through 2013. The larger than typical outage numbers and durations in 2007, 2011, and 2013 resulted from flashover because of salt contamination, excessive wind, and transformer relaying issues.

Table 4.1: Unplanned Transmission Outages

Year	Number	Hours
2004	21	10
2005	19	19
2006	20	23
2007	48	49
2008	18	24
2009	17	11
2010	23	11
2011	79	84
2012	35	22
2013	62	114

Hydro[22] uses outage cause codes to identify transmission and distribution outage causes. For transmission outages, Hydro follows CEA's approved outage cause codes for reporting outages on the transmission system for its transmission and distribution equipment outages. For its transmission system, Hydro's Energy Control Center Operators enter cause-code information into Hydro's Reliability Reporting System database after a disturbance event occurs. Hydro's Senior System Operations Engineer – Reliability (SSOE-R) [23] reviews outage cause entries, and conducts initial investigations into causes. Investigations include discussions with field staff as necessary. The reliability engineer participates in CEA workshops, at which participating utilities discuss the proper use of codes. The Association has also published manuals that provide references for reporting purposes. Hydro's transmission system cause codes include general code groups for categories that include Defective Equipment, Adverse Weather, Adverse Environment, System Conditions, Human Element, Foreign Interference, and Loss of Generation. Each code group contains more specific codes to support more detailed descriptions of causes.

For its distribution system,[24] Hydro's line crews complete a "TRO Distribution Trouble Report" for each trouble call. They forward these reports to office clerks for input into the Distribution Outage Reporting System database. Hydro's *Asset Specialist – Distribution* reviews and verifies all reports. The Asset Specialist monitors the trouble reports for each distribution feeder to identify any trends that may be developing in substandard materials or in work practices

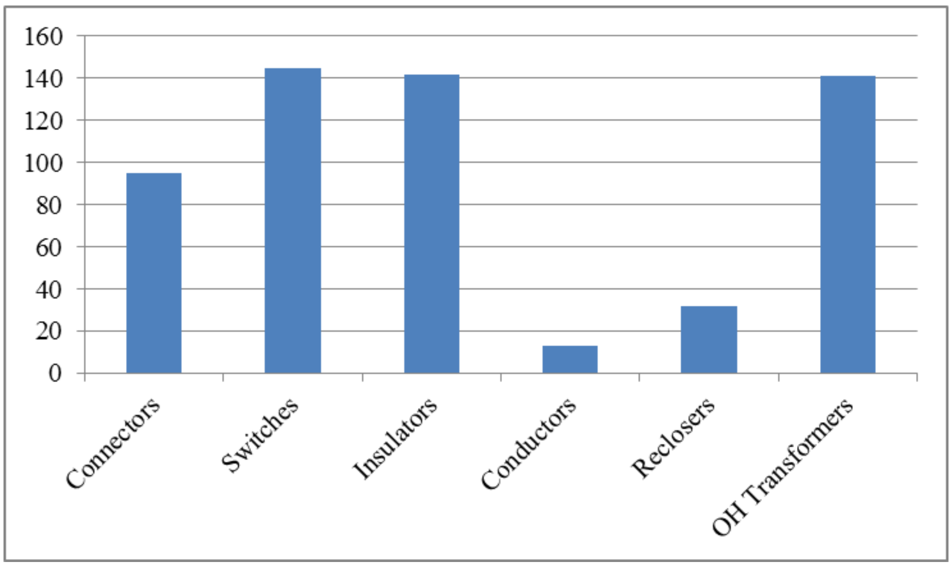
[21] Response to RFI #PUB-NLH-005.
[22] Response to RFI #PUB-NLH-185.
[23] Response to RFI #PUB-NLH-185.
[24] Response to RFI #PUB-NLH-185.

indicating the need for improvement. Hydro's distribution cause codes include Planned Outages, Loss of Supply, Tree Contacts, Lightning, Defective Equipment, Adverse Weather, Adverse Environment, Human Element, Foreign Interference, and Customer Request.

For 2009 through 2013,[25] "loss of supply" and "scheduled outages," together made up the majority of the customer interruptions in each year. The next greatest cause of customer interruptions was "defective equipment." Such events caused close to 15 percent, on average, of the customer interruptions during those five years.

The next chart[26] illustrates the causes of equipment failures. Connectors, switches, and insulators made the largest contribution to equipment-caused outages affecting customers. Failed conductors and overhead and substation reclosers also affected customers. The failure of an overhead transformer generally affects only a few customers.

Chart 4.2: 2009-2013 Numbers of Equipment Failures



2. Reliability – Planning Drivers

The asset management function (addressed in Chapters III and V of this report) has a direct and important connection with the planning process. Hydro's[27] Long Term Asset Planning (LTAP) group has responsibility for identifying and monitoring asset reliability and service level requirements, for conducting complete root cause and repeat failure analyses, and for overseeing remedial action plans for improved reliability. The asset planning group reviews outage cause trends over five years to identify repeat failures and patterns. The group also identifies further remedial actions required to improve future reliability. Responsive actions can produce near-term changes in maintenance or inventory of spares. Actions can also extend to longer range changes, such as updating of Long Term Asset Management Plans.

[25] Response to RFI #PUB-NLH-338.
[26] Response to RFI #PUB-NLH-338.
[27] Response to RFI #PUB-NLH-341.

The group has accountability for developing and refreshing Hydro's 20-plus year asset plan by addressing asset rehabilitation, overhaul, renewal, and replacement activities. Its role also involves classic elements of asset management. The group drives the development of the annual asset work plan, and provides oversight and input into the effectiveness of asset maintenance activities, including preventative and predictive maintenance.

The Long Term Asset Planning group[28] reports to Hydro's Performance and Reliability Committee. This committee reviews overall system reliability, and makes recommendations to the assigned Asset Owners for improving generation, transmission, and terminal performance and reliability. The Committee provides oversight through at least quarterly meetings. The meetings set procedures and guidelines, and review performance data. The Committee membership includes Managers in System Operations, Office of Asset Management, System Planning, Transmission and Rural Operations (TRO), Plants and Engineering.

3. Reliability – Role in Capital Planning

Hydro considers reliability issues when applying the system planning criteria it uses to determine needs for investment. These criteria guide Hydro's identification of required upgrades, replacements, and additions. The projects it includes in capital budgets after application of these criteria can contribute to improvements in reliability, particularly where existing systems are operating near their design limits. One of the bases on which Hydro prioritizes capital projects is reliability. Hydro includes a weighted scoring for reliability improvement in its ranking of potential capital projects. SAIDI and SAIFI analysis, down to the equipment component level, seeks to understand where system components may contribute to performance problems.

Hydro's[29] prioritization process considers equipment age and condition, experience, environment (such as replacing blackjack poles), reductions in maintenance costs, numbers of customers potentially affected, and potential impact to system operation. It does not, however, specifically calculate "*cost per avoided customer interruption*" in its analysis. Hydro justifies capital projects individually based on need, as required to safely, reliably, and sustainably produce and deliver electricity to customers. Hydro's capital project prioritization calculator provides a quantitative means to rank capital projects against each other. Among the factors considered are safety, legislative requirements, payback, environment, executability, customer needs and impact, overall system impact, potential loss viability, and risk mitigation.

Hydro's ranking process assigns levels to capital projects[30]. "Level 1" projects comprise those required and necessary to prevent a fatality, comply with mandatory obligations, or meet load forecasts. These highest priority projects do not get ranked against others. "Level 2" capital projects do get ranked, using a matrix of weighted criteria. Hydro formally assesses each of its projects before applying a score weighting to each criterion.
Hydro ranks each Level 2 project by evaluating and applying a weighted score for each of 12 criteria, and then summing the scores. This process provides a ranking by best overall benefit.

[28] Response to RFI #PUB-NLH-341.
[29] Response to RFI #PUB-NLH-336.
[30] Hydro's 2015 Capital Budget Application; 2015 Project Prioritization, Appendix A.

Weighting includes five levels of probability from "not likely" to "near certain." It also assigns a low, medium, or high level of confidence to the analysis. The 12 criteria are:

1. *Work Classification* - Weighting based on meeting an identified need or historical patterns of repair or replacement based on cost-benefit analysis addressing indicated cost saving and payback period. Scores range from 5 to 85, depending on cost saving and the rate of payback.
2. *Net Present Value* - Weighting based on the level the projects generate financial savings. Weighted scores range from 0 to 85, depending on the amount of savings generated.
3. *Safety Benefits* – Weighting based on the level to which they address safety-related issues (minor, treatment, lost time, or disability). The weighted scores range from 10 to 100.
4. *Environmental Benefits* - Weighting based on the level the projects are required to prevent environmental issues. The weighted scores range from 10 to 100.
5. *Alignment* - Weighting based on support provided to a company goal, a company objective, or a company department objective. The weighted scores range from 15 to 65.
6. *Schedule Risk* - Weighting based on the degree to which projects compete for available resources with other initiatives. The weighted scores range from 10 to 65.
7. *Customer Service* - Weighting based on the degree the project is needed to continue reliable service to Hydro's customers. The weighted scores range from 20 to 70 (service cannot continue without this project).
8. *Continued Service to Customers* - Weighting based on the positive impact on customer service. The weighted scores range from 10 to 70, depending on the number of customers impacted.
9. *System Impact* - Weighting based on which particular system within the company (a system with stand-by unit, a plant or terminal station, or the entire system) for which the project provides a critical need. The weighted scores range from 5 to 90 (for entire system).
10. *Impact Intensity* - Weighting based on the degree to which the project reduces repair time below Hydro's maximum acceptable downtime (MAD) of 830 MWh or 2 days. The weighted scores range from 4 to 90.
11. *Loss Type* - Weighting based on whether there was a loss risk for some equipment, a facility, a generating plant or a terminal station, or the entire system. The weighted scores range from 5 to 90.
12. *Loss Mitigation* - Weighting based on the degree that redundancy, backup options, or no mitigation options are available. The weighted scores range from 30 to 90.

4. Planning - Overall

Newfoundland Power provides a five-year peak demand requirements forecast (termed the "Infeed Load Forecast") for each location where it secures power from Hydro. Hydro addresses longer-term Island Interconnected System transmission planning analysis through production of aggregate peak forecasts for the Newfoundland Power system and the Island Rural System[31]. This longer-term process employs statistical regression techniques. Hydro addresses long-term industrial peak demands by assuming continuation of medium-term demand requirements, unless it has a known closure date for an individual customer.

[31] Response to RFI #PUB-NLH-322.

System planners use these aggregate peak demand forecasts in conjunction with modeling software to determine relationships to specified load points. Upgrading or replacement for feeders, transmission lines, substations, and breakers is triggered when modeled loading levels exceed 100 percent of the thermal rating. Non-radial feeders and transmission lines undergo an analysis of outage contingencies, for the purpose of determining whether the element understudy will experience loads beyond its 100 percent rating following system restoration and mitigation measures.

Hydro develops plans for load-growth driven capital projects addressing distribution system feeders and substations by preparing aggregate system peak demand forecasts. These annual forecasts address isolated distribution systems on the Island Interconnected System, three Labrador interconnected distribution systems, and isolated diesel systems in Labrador[32]. The standard forecast spans five years, supplemented by longer-term peak demand forecasts, as required. Hydro forecasts for its distribution systems using a combination of statistical analysis and analytical judgment. Generally, the planners review the principal rate classes for each individual system, and makes projections for them separately. Planners evaluate larger general service customer accounts individually.

Distribution systems with more than one substation get non-coincident substation peak forecasts based on the distribution system peak. Historical peak demand determination employs a number of methods. These historical peak demands, supplemented by local knowledge of new loads and the system peak demand forecast, then drive peak load forecasts for each substation. Non-coincident distribution feeder peak demand forecasts preparation follows a similar approach, with a forecast for each feeder.

Developing medium-term load-growth driven capital projects for transmission systems and the associated feeders and substations generally relies on the same aggregate system peak demand forecasts used for distribution systems. In addition to these medium-term peak demand forecasts, Hydro also relies on Industrial Customer demand forecasts and annually completed peak demand forecasts provided by Newfoundland Power. Industrial Customers directly served by Hydro provide input concerning their medium-term power requirements.

Hydro's Transmission Planning group also assists System Operations and the Energy Control Center (ECC) by performing technical analyses, operational studies, power system modeling, and dynamic system modeling. [33]

5. Planning - Transmission

Hydro's[34] Transmission System Planning Group monitors transmission systems to determine when a component's capacity fails to meet planning criteria. The group uses load flow, voltage level, short circuit current, and system stability analyses to perform this function. The identification of deficiencies leads to the preparation and testing of alternative solutions to satisfy

[32] Response to RFI #PUB-NLH-322.
[33] Response to RFI #PUB-NLH-320.
[34] Response to RFI #PUB-NLH-186.

those criteria. Where appropriate, the group conducts a least life-cycle-cost analysis of viable alternatives, and prepares detailed reports that recommend solutions. Hydro's transmission system planning group consists of four permanent employees.

Hydro[35] has planned its transmission system based on industry-representative criteria. Because of the planned connection of the high voltage DC line between the Island Interconnected System and Muskrat Falls in Labrador, Hydro has appropriately modified its steady-state analysis and transient analyses criteria for its bulk power system.

The Transmission Planning group conducts load studies to identify equipment ampacity (load-caused thermal limits) and voltage issues.[36] The group uses digital models of the system's conductor and equipment electrical impedances representing the actual line impedances under various system configurations. These studies support Hydro's annual capital budget and five-year plan. The Transmission Planning group annually prepares a set of peak and light load base case load flows for the current year and for the subsequent four years. These studies use Hydro and Newfoundland Power load forecasts. The cases studied form the basis for transmission planning criteria evaluation as part of Hydro's annual capital budgeting and five-year planning processes.

Typical outcomes of the base case load flow evaluations include identification of transformer capacity deficiencies, transmission line thermal overload conditions, reactive power, and bus under/over voltage issues. The group uses Siemens PTI Software (PSS®E) to conduct studies.

Each year Hydro[37] prepares a set of Base Case Load Flow Models for the current year and the next four years. They incorporate the latest load forecasts and completed system additions or modifications. Both peak (winter) and light (summer) load cases result.

Following the completion of the five-year base case load flows, Hydro[38] completes an annual Transformer Monitoring Exercise. This exercise assesses the transformer capacity within terminal stations, in order to ensure sufficient transformer capacity to meet the forecasted load.

Good system dynamic stability enables a transmission system, following a line disturbance, to bring back system operation to steady state condition quickly, with frequencies of the electric currents at the generators and the ends of transmission lines the same. Hydro[39] conducts *System Stability Studies* using stability models of both the Island and Labrador Interconnected Systems to assess the effects on system stability, frequency, and voltages. Transmission Planners update these models, and conduct new studies after equipment addition or modification, or when under-frequency load shedding schedules undergo modification. Hydro's stability studies are generally equipment addition driven in nature.

[35] Response to RFI #PUB-NLH-186.
[36] Response to RFI #PUB-NLH-178 and 186.
[37] Response to RFI #PUB-NLH-178 and 186.
[38] Response to RFI #PUB-NLH-178.
[39] Response to RFI #PUB-NLH-178 and 186.

Hydro completes Interconnection Studies for interconnection requests including new sources of generation (*e.g.*, wind farms) and load (*e.g.*, industrial customers). These studies may include load flow, short circuit and stability analysis. Hydro prepares cost estimates for viable interconnection solutions. Hydro conducts least-cost life-cycle costs analysis using engineering economics techniques. The analysis includes capital cost, transmission losses, incremental maintenance costs, and other factors appropriate to each project. Hydro provides a least-cost interconnection alternative to the proponent for making a decision about proceeding with interconnection. Transmission Planning integration studies typically begin with a preliminary load flow study. This preliminary work assesses the impact that proposed equipment will have on the interconnected system under normal and contingency conditions. Planners identify violations of Hydro's criteria, and test technical solutions.

Hydro[40] maintains a short circuit model of both the Island and Labrador Interconnected Transmission Systems. It updates as equipment modifications affecting short circuit levels occur. Short circuit cases for minimum, maximum and maximum foreseeable levels support work on relay settings and protection coordination, arc flash calculations, ground grid designs and equipment fault-duty specifications.

Planners repeat short circuit studies after defining technically viable solutions through the load flow and dynamics simulations. These studies assess the impact of the solution on the interrupting ratings of existing circuit breakers. The Project Execution and Technical Services group provides cost estimates for viable solutions, in order to identify least life-cycle cost alternatives.

These fault current studies identify cases where available fault currents exceed circuit breaker interrupting ratings (fault duty). [41] Hydro has not needed to replace any circuit breakers in its terminal stations because of fault duty during the last 10 years.

6. Planning - Distribution

Hydro's[42] Distribution System Planning group monitors the interconnected and isolated distribution systems. The group uses load flow and short circuit analyses to identify instances of nonconformity with planning criteria. The group responds to identified deficiencies by preparing and testing solutions that comply with criteria into the future. The group often completes least-cost life-cycle analysis of alternatives, and recommends solutions. Hydro's Distribution System Planning group consists of the Manager of Generation and Rural Engineering, two Distribution Planning Engineers, a generation planning engineer, and two market analyzers. Hydro has been planning its distribution systems to meet appropriate criteria.

The Distribution System Planning group conducts load studies. These studies use digital models of the distribution systems with conductor and equipment electrical impedances representing the actual systems. The studies identify equipment ampacity (thermal limits) and voltage issues. The Distribution Planning group performs annual reviews of each Hydro distribution feeder system,

[40] Response to RFI #PUB-NLH-178, 179, and 186.
[41] Response to RFI #PUB-NLH-321.
[42] Response to RFI #PUB-NLH-188.

using the latest load forecast information. The annual system review checks for violations of distribution criteria (*e.g.*, equipment overloads and abnormal voltages), using load flow analysis techniques. The size of the individual system under analysis limits the depth of the study and the detail of the model. Larger systems experiencing load growth undergo load and voltage study (recording voltages and currents on the distribution system during peak load periods) at least every five years. These studies ensure that modeling represents actual field conditions. Larger systems with little load growth must undergo load and voltage study every ten years. Smaller distribution systems (such as those on isolated diesel systems) may not require load and voltage study.

The annual system review supports Hydro's annual capital budget and five-year plan. Typical results of the annual system review process include transformer capacity deficiencies, and thermal overload conditions. The review may also disclose under/over voltage issues requiring reactive power devices or voltage regulator additions, line re-conductoring, circuit breaker or recloser replacements and diesel generator capacity/fuel storage additions.

7. Planning - Equipment Loadings

Hydro's[43] anticipated winter 2014/2015 peak demands versus conductor ratings at 0˚ C, with normal configurations indicate that none of Hydro's twenty-four 230 kV lines, sixteen 138 kV lines, and sixteen 66/69 kV lines will be loaded to near line conductor ampacities this winter. Similarly, no anticipated winter peak demands[44]should require any of Hydro's 67 terminal station and substation transformers to operate in excess of nameplate ratings, while operating under normal configurations. All N-1 contingency terminal stations (*i.e.*, loss of one transformer in a substation or in one of the 138 kV loops) should have sufficient transformer capacity to face the loss of one transformer, following the replacement of a 125 MVA T1 transformer at Sunnyside Terminal Station. The Stony Brook Terminal Station comprises an exception to this observation. It may require some transfer of loads to other terminal stations.

At the time of this writing, the new 125 MVA transformer for replacing the failed T1 transformer at Sunnyside Terminal Station will not be installed by the time the 2014/2015 winter peak demand occurs. Hydro, however, has relocated the 125 MVA T8 transformer from Holyrood Terminal Station to the T1 position at Sunnyside Terminal Station. Hydro plans to install the delayed new transformer later in the winter at Holyrood, rather than at Sunnyside. Based on the peak demand loading forecast, Holyrood Terminal Station transformer capacity is sufficient to continue N-1 contingency operations through the 2014/2015 peak demand. Based on Hydro's June 16, 2014 *Report on Terminal Stations*, relocation of the Holyrood T8 transformer from the Western Avalon – Holyrood 138 kV loop, to replace the failed 125 MVA T1 transformer at Sunnyside Terminal Station, will provide sufficient transformer capacity to support the Stony Brook – Sunnyside 138 kV loop without causing a transformer capacity issue for the Western Avalon – Holyrood 138 kV loop.

[43] Response to RFI #PUB-NLH-324.
[44] Response to RFI #PUB-NLH-323.

Comparing Hydro's[45] anticipated 2014 peak demand data with the conductor rating capacities of each of its 78 feeders indicates adequate capacity for the coming winter. Hydro expects only one feeder to experience peak loadings greater than 50 percent of its rating during the coming winter's peak. Even that feeder should reach only 73 percent of its rating under those conditions.

8. Planning – Progress in Implementing Corrective Actions

As noted earlier, Hydro produced an Integrated Action Plan (the Plan) to incorporate the actions required to implement Liberty's 2014 Interim Report recommendations, the Board's directions in its Interim Report and additional actions identified by Hydro. The Plan included actions related to System Planning. Liberty addresses progress against the system planning actions through Hydro's report on the Plan of December 10, 2014. Note that our review was not scoped to include independent, field verification of work performance. Liberty's scope included a review of Hydro's reports and discussions with management. Below is a list of the status of each action related to Planning, based on Hydro's Integrated Action Plan reporting as of December 10, 2014.

Item 21 from the Plan provides as follows, and listed a due date of June 15, 2014:

> *Complete system studies in relation to the relocation of the repaired T5 transformer from Western Avalon to Sunnyside in case a replacement for T1 transformer is not ready.*

Hydro lists this item as complete, reporting the completion of a system study on June 13, 2014. Manufacturer delays on the new transformer for Sunnyside led Hydro to conclude in October 2014 that the new T1 transformer would likely not be ready for service until later this winter. Hydro decided relocating the repaired T5 transformer at Western Avalon was not the best solution. Hydro decided instead to relocate the Holyrood T8 transformer to Sunnyside Terminal Station. Hydro's Sunnyside Replacement Equipment Status Update Briefing, dated November 21, 2014, noted that the T1 transformer (formerly Holyrood T8) was on track for entering service by November 30, 2014. It is now in service. The newly manufactured transformer originally assigned to replace the Sunnyside T1 transformer has been delivered to Holyrood and installation work is ongoing. Hydro's 138 kV loops will be restored to full designed transformer capacity when the Sunnyside T1 and the Holyrood T8 transformer are both placed into service.

Item 22 from the Plan provides as follows, and also listed a due date of June 15, 2014:

> *Complete a study in relation to the availability and necessity of a replacement transformer for T5 at Western Avalon, addressing schedule, estimated costs, the resources required, and how these requirements will be met.*

Hydro lists this item as complete. It reports completion of the study in June and an October repair completion and ready for service date for the T5 transformer. In its Western Avalon Terminal Station T5 Tap Changer Status Update Briefing of November, 7, 2014, Hydro reported that the T5 transformer was returned to service during the third week of October.

Item 23 from the Plan provides as follows, and also listed a due date of September 15, 2014:

> *Complete a study to determine if abnormal system disturbances may have caused the T5 failure at Western Avalon.*

[45] Response to RFI #PUB-NLH-325.

In its December 10 report, Hydro listed this item as complete, and stated that the report would be submitted to the Board. Liberty has not reviewed this report.

9. Design – Standards and Criteria

a. Line Construction

Hydro[46] employs transmission and distribution conductor clearance and pole strength criteria consistent with the Canadian Standards Association (CSA) Overhead Systems criteria. This standard undergoes revision every five years, with revisions applicable to lines built after the release of the updated standard. Hydro only applies new standards to existing lines when upgrading an existing line. Hydro has for many decades designed its system to withstand extreme wind gust loads of 176 kilometers per hour (1,500 Pa pressure). Hydro has long used a standard of 25.4 mm radial glaze ice in "Normal Zones" and 38 mm radial glaze ice in "Ice Zones." Hydro has applied the Ice Zone criteria for small sections of the line system.

The Canadian Standards Association formerly stipulated weather loads based on three categories: Heavy, Medium A, and Medium B. Newfoundland and Labrador generally fall into the Heavy category. The association changed the weather loading districts in 2001, introducing the new category of Severe Loading district (19 mm ice and 400 Pa wind). This 2001 change also redefined the previous three categories as well. The Severe Loading category applies only to the Avalon and Bonavista Peninsulas, with the rest of the Hydro system under the Heavy Loading category. The reclassification produces the need to consider a net increase of 22 percent in conductor loads. This change remains generally within Hydro's design limits however, because the extreme wind load governs in most cases. All of Hydro's transmission lines comply with the association's Heavy Loading criteria with an overload capacity factor of 2.0.

Hydro[47] applies transmission conductor phase-to-phase and phase-to-ground clearances consistent with CSA Standards, CAN/CSA – 22.3 – Overhead Systems.

b. Thermal Loadings

Hydro[48] applies a design criterion that calls for its electric systems to operate without exceeding conductor and equipment thermal loading ratings (including transformer nameplate ratings) during peak loads forecasted across its five-year planning horizon. Distribution line loading should not exceed the line rating.

c. Conductor Loading Practices

Generally, the rated capacity of the lines is based on the maximum allowable operating temperature. Hydro has also adopted IEEE Standard 738 for determining the amperage for distribution system conductors. When transmission line energy flow exceeds the maximum thermal rating of the line or if it appears that the energy flow will exceed the rating of the line in

[46] Response to RFI #PUB-NLH-314.
[47] Response to RFI #PUB-NLH-317.
[48] Response to RFI #PUB-NLH-176.

the shorter term, Hydro's[49] Energy Control Center operators will initiate action to relieve the overload or possible overload. In the event that line loadings do not fall to the thermal rating of the line within 30 minutes, Hydro will initiate customer load shedding.

Hydro must avoid exceeding CSA[50] line to ground (sag) clearances. The line height and structure spacing distances of Hydro's vintage (1960s and 1970s) lines prevent it from operating those lines at conductor temperatures greater than 50° C and with more than 0.5 to 1.5 inches of radial ice. The case for the rebuilt (1999 through 2002) steel tower 230 kV transmission lines on the Avalon Peninsula differ. Those lines provide adequate clearances to ground at maximum conductor temperatures of 80° C and with even greater radial ice loading.

d. Power Transformer Loading Practices

Hydro prevents customer outages during abnormal system configurations[51] by allowing operation of its terminal station transformers to exceed the manufacturers' nameplate ratings. Transformer loading guidelines permit terminal station transformers to operate up to at a "hot spot" temperature (maximum winding conductor temperature) of 110° C. Hydro, however, applies operating limitations for specific transformers, considering ambient temperature, thermal ratings of connected equipment, the cooling medium, the history and age of the transformer, the dollar value, and consequences should the transformer fail because of overloading. Hydro is currently completing a review of its transformer loading instructions in coordination with Newfoundland Power. This review includes loss of transformer life calculations associated with operating a transformer up to the maximum 140° C (damaging) hot spot temperature limit for a short time during an emergency, followed by a prolonged time at less than 100° C hot spot temperature.

10. Design - Transmission

a. Load Transfer Capability

The ability to transfer loads from one transmission line to another line improves reliability and system stability when transmission equipment is not in service because of an emergency or maintenance work. Hydro's 230 kV transmission lines and many of its 138 kV transmission lines have N-1 contingency resulting from parallel lines or loops. Hydro has also installed N-1 contingency 230/138 kV and 230/66 kV transformer capacity (two or more transformers) in its terminal stations except at the 230/66 kV Buchans Terminal Station and the Stephenville 230/66 kV Terminal Station. For the loss of the single transformers, the Stephenville Combustion Turbine can supply the loads for its station, but the Star Lake Hydroelectric generator, however, is not able to fully supply the Buchans Terminal Station loads. Hydro should be able to use the two surplus 230/66 kV transformers which will be made available by the on-going Hardwoods - Oxen Pond Terminal Station transformer capacity project as spares for these terminal stations.

[49] Response to RFI #PUB-NLH-316.
[50] Response to RFI #PUB-NLH-317.
[51] Response to RFI #PUB-NLH-315.

b. *Terminal Station Bus Configurations*

Hydro refers to its transmission substations as "Terminal Stations." Switches, circuit breakers, and interconnecting conductors (large wires and tubes) called buses connect transformers and source and supply lines within the terminal stations. In some cases, Hydro can configure these buses in various ways to provide differing levels of redundancy to address cases where one source, transformer, or circuit breaker is out of service. Hydro[52] uses several bus configurations in its terminal stations, including load buses, ring buses, breaker and a one-half buses, and breaker and one-third buses.

c. *Transmission System SCADA*

Sectionalizing and Data Acquisition (SCADA) controlled monitoring and sectionalizing supports the control and reliability of a transmission system, and provides system information for the Energy Management System (EMS). Hydro[53] owns and maintains 52 high voltage terminal stations, operating at 230 kV, 138 kV and 66/69 kV on the Island Interconnected System. Thirty-seven of these stations have SCADA control and monitoring. One station has some monitoring but no control; 14 terminal stations have no remote control or monitoring. These terminal stations are:

138 kV Bottom Waters	69 kV Barachiox	69 kV Coney Arm
69 kV Conne River	69 kV English Harbour West	69 kV Hampden
69 kV Jackson's Arm	69 kV Main Brook	69 kV Parson's Pond
66 kV Duck Pond	66 kV Glenburnie	66 kV Rocky Harbour
66 kV Sally's Cove	66 kV Wiltondale	

The Corner Brook Frequency Converter has some level of monitoring only.

From an operational perspective, all of the stations that have no control or monitoring directly connect to a distribution system (*i.e.*, they supply customers). The Energy Control Center uses the SCADA information from nearby connected stations or from customer outage reports to determine if there is an issue at or downstream of the uncontrolled and unmonitored station. If there are issues detected, the Energy Control Center will dispatch crews to the affected station. The crews will then report back to the Energy Control Center when the problem is found and what the expected restoration time will be.

Of the 56 transmission circuits,[54] 53 operate under SCADA or another monitoring and control system. The three exceptions are as follows:

- TL229: Wiltondale – Glenburnie (66 kV),
- TL252: TL252 Tap – Jackson's Arm (66 kV), and
- TL253: Jacksons Arm – Coney Arm (66 kV).

[52] Response to RFI #PUB-NLH-319.
[53] Response to RFI #PUB-NLH-102 and 405.
[54] Response to RFI #PUB-NLH-406.

d. Lightning and Voltage Surge Protection

Preventing transmission line equipment damage and faults caused by transient overvoltages is a function of line design, grounding, relaying, and the use of lightning arrestors. Hydro[55] installed lightning rods on each of its transmission line structures to protect the lines from lightning surges. For wood pole lines, the lightning rod is connected to a solid steel wire, which runs down the length of the pole, and connects to a counterpoise system at the base of the structure to dissipate the energy. For steel structures, Hydro connects the lightning rod to the steel lattice structure and bonds all hardware to the structure, and connects the structure to the buried grounding counterpoise system under the transmission line.

Hydro generally did not install continuous overhead ground wires on its transmission lines when constructing them. Hydro did not install lightning surge arresters on its transmission lines; however, Hydro did retrofit TL206 (Bay d'Espoir to Sunnyside) with lightning arresters at *each tower* because of numerous lightning strike events causing the loss of both TL206 and its parallel circuit TL202. For future 230 kV transmission line construction, Hydro will install continuous overhead ground wires with integrated fiber optic cable for improved lightning protection and relaying communication between terminal stations.

Hydro installed overhead ground wires on its transmission lines from the terminal stations out for 1.6 kilometers to protect the lines from lightning strikes. It has installed lightning arresters on the high and low voltage windings of terminal station transformers.

Except at 230 kV and 66 kV switched capacitor banks, surge arresters have not been needed on Hydro's transmission system. Hydro's equipment designs and transmission line air clearances are sufficient to withstand the transient overvoltages, based on system engineering studies and operating experience.

Hydro is aware that Gas Insulated Switchgear switching operations can result in significant very fast front transient over voltages. The 230 kV Gas Insulated Switchgear at Cat Arm is equipped with surge arresters on the 230 kV bus at the Cat Arm Terminal Station. Further, with the replacement of original air blast circuit breakers with gas insulated (SF6) circuit breakers, Hydro will be installing surge arresters on 230 kV line terminations in SF6 circuit breaker terminal stations where determined necessary.

e. Animal Protection

Animal-caused electrical faults can affect the reliability of electric systems, especially for substation distribution voltage equipment. Hydro, however, does not have a practice for installing animal guards, other than for large birds (raptors). Hydro[56] protects transmission and distribution systems from raptors based on the exposure experienced in different areas. If Hydro discovers a raptor nest on a transmission or distribution structure, it records the location, and monitors its condition through annual helicopter patrols or other inspections. If at any time the nest is found to be in danger of contacting energized equipment, it is relocated to another pole or

[55] Response to RFI #PUB-NLH-329.
[56] Response to RFI #PUB-NLH-330.

to a pole installed at the edge of the right-of-way adjacent to the original structure. Hydro also installs bird "deterrent spikes" on some transmission structures in areas prone to outages due to birds roosting on structure cross arms above insulator strings.

f. Transmission Line Vibration and Galloping Mitigation

Wind and ice-caused conductor oscillations (so-called galloping) can damage transmission line hardware. Hydro[57] mitigates vibrating or galloping conductors" by installing "air flow spoilers;" helix shaped wires that are wrapped on the conductors and are designed to maintain aerodynamic stability and counteract the wind caused vibrations and related phenomenon known as galloping, by installing "inter-phase spacers" in span insulated couplings between phases to maintain phase-to-phase clearance to avoid flashovers, and by installing "detuning pendulum weights" attached to the line to interrupt the torsional movement of the wire, preventing galloping.

11. Design - Distribution

Of Hydro's[58] 52 distribution substations (including some terminal stations which also have transformers serving the distribution system) located on the IIS, eight percent can be served by more than one source, either at the station itself or downstream on a distribution line. The substation transformers in Hydro's distribution substations on the IIS are comprised of transformers banks ranging in size from 1,000 kVA to 16,670 kVA. Hydro has two substations that have multiple transformers that operate in parallel and provide redundancy to their respective systems.

Hydro has 79 overhead distribution feeders. In case of emergencies and for planned maintenance outages, 11 can be tied together to transfer feeder load. Hydro[59] does not have any mainline underground distribution feeders and has only one Underground Residential Distribution (URD) lateral feeder in service, serving only 17 customers, located in the town of Milltown on the Bay d'Espoir distribution system.

Hydro maintains spare distribution transformers either on-site or at other locations. It can also use Newfoundland Power's mobile equipment for isolated diesel systems and single transformer distribution substations.

a. Distribution Feeder Equipment Lightning Protection

Where isokeraunic (lightning activity) levels are known to be high, Hydro protects[60] its distribution substations with lightning arresters on each feeder at the substations. It protects its distribution feeders with lightning arresters at feeder supplied distribution transformers. It installs lightning arresters on all capacitor banks and submarine cables.

[57] Response to RFI #PUB-NLH-331.
[58] Response to RFI #PUB-NLH-310, 312, and 313.
[59] Response to RFI #PUB-NLH-161.
[60] Response to RFI #PUB-NLH-329.

b. Distribution System SCADA

Automatic and SCADA controlled sectionalizing is necessary for the control and reliability of a distribution system. On the Island Interconnected System, Hydro[61] owns and maintains 34 distribution systems. Ten of these systems have some level of remote control and monitoring while the remaining 24 have no remote control or monitoring.

12. Design - Geographic Information System (GIS)

A GIS provides a digital record of a utility's equipment locations and electrical connectivity, and usually includes other important equipment data critical for operating the system, for conducting engineering studies, and for managing equipment repairs and maintenance. A GIS system for Hydro's[62] Transmission and Distribution Network is under development. Once completed, the system will use ESRI ArcGIS software to store information on the specific equipment data, component condition, as well as location of the facilities. To date, the Transmission system is approximately 65 percent complete with an expected implementation in 2015. A distribution Geographic Information System remains in the early stages of development.

Currently, all of the field information for the system is recorded by area personnel (line crew or technicians) and entered into an electronic data collector for uploading into a database. To ensure accuracy of the information, the data is currently being verified by the Transmission Design section of Project Execution and Technical Services.

13. Protection and Control - Organization

The Protection and Control group professionals consist of Engineers and Technologists. The Engineers, working from St. John's, provide project execution and technical services. The Technologists conduct commissioning and maintenance testing, operating from various locations. The scope of the group's responsibilities includes protective relaying, control relaying, distributed control systems (DCS), programmable logic control, governor and excitation systems, metering, and uninterruptible power supply systems.

The Protection and Control Engineers[63] provide project management and technical support, operating as part of the asset management function. The Engineers perform engineering design, from the conceptual stage to final feasibility. Hydro does not yet have a formal Protection and Control design criteria document.[64] Existing Protection and Control Standards specify mostly functional requirements for equipment and specific standards of acceptance. Hydro is preparing formal protection design standards and criteria as directed by the Board in its Interim Report.

The engineers have responsibility for project budgets, work preparation, design procurement, contract preparation, and inspection and testing of equipment and systems. They develop design standards and procedures, evaluate procurement requirements, award project contracts, provide

[61] Response to RFI #PUB-NLH-102.
[62] Response to RFI #PUB-NLH-351.
[63] Response to RFI #PUB-NLH-347.
[64] Response to RFI #PUB-NLH-327.

engineering support during construction and commissioning, and may direct those installing certain equipment and systems.

Ongoing support roles include ongoing work with field operations personnel, which include detailed analysis of operating systems and maintenance problems. The Protection and Control Engineers review system events and outages, and provide technical support in addressing resulting findings. They carry out protection coordination studies for generator, transmission and distribution line settings. They also prepare settings for relays used in generating units, terminal stations, transmission lines, and distribution systems.

Protection and Controls Technologists supplement the work of the Engineers.[65] Technologist duties include installing, testing, maintaining and modifying protective relays, meters, and instrumentation and control equipment associated with generation, transmission, and distribution. The Technologists also perform other tests that relate to the primary equipment insulation integrity (*e.g.*, power factor and dielectric tests). They also maintain equipment historical test records that serve to compare and evaluate equipment performance.

The Technologists also support the commissioning of major system components. They troubleshoot and test system components and protection and control schemes. They also prepare and maintain as-built drawings for new and modified installations.

Staffing remained essentially the same from 2009 through 2013 (from 21 to 20). Hydro added two Technologists in 2014. A temporary addition of an equivalent half-time person will assist in completion of non-recurring 2014 work. Hydro's 2015 work planning has disclosed no need for additional resources to complete base work. The Protection and Controls group, however, will employ an additional equivalent of 1.5 people through 2015 to complete non-recurring work.

14. Protection and Control - Device Coordination Studies

Hydro uses an Aspen OneLiner® software package to model the transmission and distribution systems and their protective devices, and to perform relay coordination studies.[66] Modeling also assists in ensuring that proper coordination remains following changes to generating, transmission, or distribution systems. Hydro also generally uses the Aspen software for arc flash studies, which determine levels of personal protection equipment and clothing for employees working near energized equipment. Hydro uses Aspen OneLiner® to model the different voltage level systems and to perform relay coordination.[67] Aspen OneLiner® models the effects of changes to the relaying scheme for transmission and distribution configurations. It also assists when calculating arc flash energy (for determining the level of personal protection equipment needed when working near energized switchgear) results for generating plants. Hydro has used a different software package (SKM Power Tools) for a Holyrood arc flash study. Aspen OneLiner® did not have a flash calculator available at the time of the Holyrood arc flash study.

[65] Response to RFI #PUB-NLH-167.
[66] Response to RFI #PUB-NLF-178.
[67] Response to RFI #PUB-NLH-178.

15. Protection and Control – Transmission System Modernization

Hydro's transmission line and bus relay protection design criteria and designs have progressed over the years to adapt to changing system conditions and to the availability and functionality of modern microprocessor relays.[68] These relays have many advantages over old electromechanical and even newer electronic relays. Microprocessor relays remain accurate, and can perform multiple protective functions. Self-diagnostic capability in combination with other programmable monitoring capacity improves relaying system reliability and reduces maintenance costs. The new relays communicate with the SCADA system, providing additional remote control capabilities that increase operational field staff efficiency. The new relays also provide remote access to relay event and disturbance records.

Hydro has added microprocessor-based relays to provide increased flexibility in settings, and to provide the capability to monitor system conditions occurring during disturbances. Personnel can retrieve disturbance records from the master station in Hydro Place for analysis. These analyses drive changes to protection designs and settings to improve reliability.

Hydro expended about $270,000 in 2009 to replace obsolete relays with modern microprocessor transmission line protection relays at Berry Hill, Peter's Barren, Plum Point, Bear Cove, and Roddickton Woodchip terminal stations.[69] Hydro expended about another $170,000 in 2010 to upgrade relay protection at the Western Avalon terminal station. It replaced electromechanical protection and reclosing relays with microprocessor relays, and installed a current differential relay system for Primary Protection 1, for the line to Voisey's Bay Nickel terminal station. Hydro did not make expenditures for relay replacements from 2011 through 2013.

Protective relay system design studies conducted in 2010 and 2011 identified where protective relay system upgrades would provide the most effective improvements in transmission operations.[70] A consultant evaluated relay applications and settings on ten Hydro transmission lines. These studies led to a 2012 plan to spend about $670,000 to replace obsolete relays for the Holyrood to Hardwoods transmission line during the 2013-2015 time period. Hydro decided in 2013, however, not to replace the relays because the future installation of the Soldier's Pond terminal station would have required further changes to that relay protection system. Hydro now plans to implement recommendations from the 2010 and 2011 protection studies.

An Internal Power System Review and Analysis Committee conducted a root cause analysis following the January 2013 outage events. The study sought to identify whether relay issues contributed to events.[71] The study led to June 2013 recommendations to address transmission protection issues. The recommendations included replacing a number of obsolete relays. Hydro has since 2009 replaced obsolete panels on distribution automatic circuit reclosers, installing reliable programmable control panels. The next table summarizes these replacements.[72]

[68] Response to RFI #PUB-NLH-327.
[69] Response to RFI #PUB-NLH-100, 108, and 328.
[70] Hydro's 2013 Budget Application.
[71] Response to RFI #PUB-NLH-108 and 160.
[72] Response to RFI #PUB-NLH-100.

Table 4.3: Expenditures for Protective Relay Replacements

Type	2009	2010	2011	2012	2013
Relay Replacements	$264,295	$172,173	$0	0	$0
Distribution Recloser Control Panels	107,238	164,552	178,400	113,936	148,180
230 kV Breaker Controls	59,706	0	$0	$0	78,452
Totals	431,239	336,725	178,400	113,936	226,632

Hydro anticipates further expenditures for relay and recloser control panel replacements, as indicated in the next table. Hydro conducted a root cause analysis to identify and resolve protective relay and control malfunctions contributing to the January 2014 events.[73] Hydro is also formalizing its transmission protection philosophy (including breaker failure protection designs) to make it a protection and control standard, and to implement justified recommendations resulting from previous protective relay studies undertaken several years ago.

Hydro anticipates spending about $240,000 in 2016 in the third year of the project to replace relays on TL201, TL217 and TL242 as part of the Soldier's Pond Terminal Station construction. Hydro also plans expenditures of about $300,000 in 2015 to replace breaker failure protection in Bay d'Espoir and line protection on 130L and 133L at Stony Brook.[74] Hydro anticipates replacing breaker failure protection and 138 kV and 66 kV line protections at various terminal stations, beginning in 2017. The next table summarizes total anticipated expenditures for Protection and Control modernization.

Table 4.4: Anticipated Protection and Control Expenditures

Type	2014	2015	2016	2017	2018
Relay Replacements	$151,902	$1,024,300	$546,400	$631,000	$631,000
Recloser Control Panels	$110,300	$84,400	$0	$0	$0
230 kV Breaker Controls	$0	$64,750	$0	$0	$0
Totals	$262,202	$1,173,450	$546,400	$631,000	$631,000

16. Protection and Control – Maintenance and Testing

The protection and control preventive maintenance work plan has included:[75]

- Testing power transformers, current transformers, potential transformers and oil circuit breakers on a six-year cycle
- Testing and maintaining relays, including cleaning, function testing, and verification of correct settings on a six-year cycle
- Testing and maintaining meters, including cleaning, calibration checks, and verification of correct operation on a six-year cycle.

Hydro made two additions to the work plan starting with 2014 in response to the recommendations in Liberty's 2014 Interim Report and the directions in the Board's Interim Report:

[73] Report to the Board Related to Protection and Control Systems, June 16, 2014.
[74] Response to RFI #PUB-NLH-383.
[75] Response to RFI #PUB-NLH-348.

- Exercising all breakers to verify correct operation on a one-year cycle
- Operating circuit breakers directly from protection systems, simulating actual conditions on a four-year cycle for air blast breakers and on a six-year cycle for all other breakers.

Hydro tests transmission system relays on six-year cycles, using Doble Relay Software.[76] Hydro's technologists follow Hydro's Protective Maintenance Procedures. The Procedures addressed function and accuracy tests, and included trip circuit tests to blocking switches and lock out relays (and not to the breakers, except when conducting commissioning tests). Hydro had not been tripping circuit breakers from lock out relays, because of the risk in tripping customers off during this testing. However, in response to Liberty's recommendations, Hydro updated its six-year protective relay testing procedure following the January 2014 events. Its revised Breaker Function Testing Maintenance Procedure of July 2014 seeks to ensure verification of the complete tripping circuits, including the breakers, in a safe and secure fashion.

Preventive maintenance orders include Protection and Control activities at terminal station equipment.[77] The next table summarizes progress on such work, through September 28, 2014.

Table 4.5: Relay Preventive Maintenance Backlogs

Year	Scheduled	Completed	Backlog
2011	16	15	2
2012	18	12	2
2013	17	20	6

The next table summarizes the corrective maintenance backlogs involving terminal station protective relaying, with backlogs again listed as of September 2014.

Table 4.6: Protective Relay Corrective Maintenance

Year	Scheduled	Completed	Backlog
2011	5	5	0
2012	11	6	1
2013	51	55	6

The increase in corrective maintenance work orders in 2013 results primarily from breaker exercising needs identified as a result of the January 2013 events. Hydro reported that it will complete all 2013 preventive and corrective maintenance backlogs by the end of 2014.

Asset Specialist and Equipment Engineers[78] in the Transmission and Rural Operations (TRO) group typically investigate unexplained relay operations for less complex system events. Protection and Control Engineers, Project Execution and Technical Services Engineers, and System Operations Engineers investigate more complex conditions or events.

[76] Response to RFI #PUB-NLF-326.
[77] Response to RFI #PUB-NLH-380.
[78] Response to RFI #PUB-NLH-372.

17. Protection and Control – Progress in Implementing Corrective Actions

The principal Protection and Control items in the Integrated Action Plan comprise:

- A plan to review, by November 30, 2014, existing station breaker failure design and of stations without breaker failure protection
- A standard for breaker failure, prepared by November 30, 2014, that will clearly set criteria for future designs and modifications needed for existing installations
- A review of key priority alarms to be provided to the operators in the Energy Control Center, by November 28, 2014
- A plan to implement modern digital relays that can record disturbance information, by October 24, 2014
- Relay setting changes to improve performance, completed by December 15, 2014.

We review below Hydro's status (by Integrated Action Plan item number) of the Protection and Control items, as of December 10, 2014. We did not verify actions through field inspection, but relied upon Hydro status reports and discussions with management.[79]

a. *No. 46: Eliminate slow trip coils on Air Blast Circuit Breakers.*

Hydro reports this item (having a due date of November 30, 2014) as complete, stating that it has rewired backup relay protection for all circuit breakers with slow trip coils to the breakers' fast-trip coils.

b. *No. 47: Develop a plan to redesign existing breaker failure relay protection schemes to provide that the breaker failure schemes will be activated with either a 138 kV or 230 kV breaker malfunction after a transformer failure; and install breaker failure relay protection for transformers in terminal stations where breaker failure relay protection is not in place.*

Hydro reported that this item (having a due date of November 30, 2014) was delayed until December 19.

c. *No. 49: Implement all other P&C and related Root Cause Analysis recommendations identified in Hydro's Integrated Action Plan.*

Hydro reported that it had assigned internal resources to coordinate the implementation of these 60 recommendations by December 15, 2014. As of December 10, 2014, 46 items were reported as complete with the remainder to be completed by January 31, 2015.

d. *No. 50: Execute a 2014 plan to repair and update terminal station relay operations cards.*

In its October report Hydro reported the work to be on schedule for completion by the due date of November 30, 2014, with fifty percent of all terminal station relay cards audited and the remaining being scheduled for auditing. Its December 10 report stated that the work was delayed and will be completed by December 31, 2014.

[79] Updated Integrated Action Plan as at the end of September, 2014.

e. No. 51: Document a protection philosophy and P&C engineering standard in 2014.

Hydro reported that this work is completed.

f. No. 52: Develop a plan for meeting the Company's substation and protection and control system resource requirements beginning in 2014.

Hydro reported this item as complete. It has developed a longer-term resourcing plan for meeting base needs, and included it as part of the proposed 2015 operating budget. The annual work planning process will drive resource requirements for 2016 and beyond.

g. No. 53: Implement all outstanding recommendations from the 2010/11 P&C studies.

Hydro reports that completion of this work has been delayed, with thirteen items complete, and the remaining four scheduled to be completed by January 31, 2015.

h. No. 54: Implement all outstanding P&C recommendations from the 2013 winter events study.

Hydro reports that work has progressed in line with the plan and in conformity with the December 31, 2014 completion date.

i. No. 43: Develop a plan for updating event and data recording devices, systems and procedures to identify the key set of priority alarms, to provide for the monitoring of alarms, and to address staff training and equipment repair.

Hydro reports that this is completed.

j. No. 44: Complete an analysis of the implementation of a program to install modern digital relays for all major equipment such as 230 kV transformers.

Hydro reported that this is complete. The analysis will lead to installation in future years.

D. Conclusions

Reliability

4.1. Customers on the IIS experienced a greater number of lengthy interruptions because of planned transmission system maintenance than because of forced interruptions. *(Recommendation No. 4.1)*

A primary reason for this arises from the number of radial transmission lines that Hydro operates to serve several terminal stations without backup generation. This configuration particularly affects the Great Northern Peninsula (GNP). Radial transmission lines involve outages when conducting maintenance. Hydro has experienced roughly average Central-Rural transmission-forced outage rates in recent years, but much higher planned outage rates. Forced Outage T-SAIFI and T-SAIDI were more or less consistent with CEA average indices. The number of T-SAIDI hours resulting from planned outages was about twice those resulting from forced outages. The Northern Region has experienced greater than average transmission-forced outages, but excluding the atypical years 2011 and 2013 brings the results into general conformity with experience.

Planned Hydro transmission outages have also caused considerable impact to Newfoundland Power customers. Forced Hydro outage frequencies and durations affecting Newfoundland Power were moderate, when excluding major events and the atypical years of 2011 and 2013. Forced outages, however, caused considerable impact (about 32 minutes of interruption on average per year per Newfoundland Power customer).

4.2. Transmission-forced outage frequencies and durations both increased from 2009 to 2013.

The major events of 2011 and 2013 had significant impact on T-SAIFI and T-SAIDI between 2009 and 2013. Nevertheless, even after adjustments for major events, declining performance occurred. Excluding major events:

- Northern Region forced T-SAIFI was about 1.2 interruptions in 2009 and 2.3 in 2013.
- Northern Region forced T-SAIDI was about 43 minutes in 2009 and 74 in 2013.
- Central-Rural Region forced T-SAIFI was about 0.1 interruptions in 2009 and 0.4 in 2013.
- Central-Rural Region forced T-SAIDI was about 0.1 minutes in 2009 (52 in 2010), and 55 minutes in 2013.
- Newfoundland Power interconnection forced T-SAIFI was about 0.1 interruptions in 2009 and 0.2 interruptions in 2013.
- Newfoundland Power interconnection forced T-SAIDI was 2.7 minutes in 2009 and 31 minutes in 2013.

4.3. Distribution outage frequencies and durations have increased, but remain consistent with Canadian averages after adjustment for major events.

Central Region average Distribution Forced Outage SAIFI from 2009 through 2013 compared reasonably well with the Canadian Electricity Association (CEA) average, even when including the system-caused outages in 2011 and 2013. Average SAIFI for Hydro’s Northern Region, however, was 50 percent greater (worse) than the corresponding number for the Central Region. Excluding 2011 and 2013 data, both Regions’ average SAIFI compares with CEA average data for the three remaining years. Distribution outage durations on the Island Interconnected System for both Hydro Regions were 50 percent greater than the CEA averages when all major events are included. However, excluding major events and data from 2011 and 2013 produces SAIDI metrics better than CEA averages.

Nevertheless, distribution forced outage durations for both Regions increased from 2009 to 2013, even after excluding major events:

- Northern Region Distribution forced SAIFI was about 2.1 interruptions in 2009 and about 2.2 interruptions in 2013.
- Northern Region Distribution forced SAIDI was about 2.8 hours in 2009 and 3.80 hours in 2013.
- Central Region forced SAIFI was about 2.0 interruptions in 2009 and 2.5 interruptions in 2013.

- Central Region forced SAIDI was about 3.1 hours in 2009 and 6.7 hours in 2013.

4.4. Loss of supply and scheduled outages have been the largest contributors to outages.

"Loss of supply" and "scheduled outages" together caused the majority of customer interruptions in each year of the period 2009 through 2013. Scheduled outages cause customer interruptions because Hydro does not always have feeder ties or back up generation. The next greatest cause of customer interruptions was "defective equipment," which caused close to 15 percent, on average, of the customer interruptions during those five years.

4.5. Connectors, switches, and insulators made the largest contribution to equipment caused outages.

Failed conductors and overhead and substation reclosers also affect customers.

4.6. The lack of a focused worst-feeder program creates a gap in addressing reliability issues. *(Recommendation No. 4.2)*

Prioritization of distribution capital work seeks a structured plan for replacing aged and failure-prone feeder equipment. Evaluations consider SAIFI and SAIDI performance, but include many other criteria in capital planning. Thus, worst performance alone cannot justify spending on particular feeders. Many utilities conduct programs focused just on worst performing feeders, in order to mitigate future customer interruption numbers and durations. Such programs do not make cost a material factor in capital planning for such feeders. Utilities that take this approach do so in addition to other programs for rebuilding aged distribution systems. Often worst-feeder programs target a fixed percentage of worst performing feeders to address each year.

4.7. Hydro does not compare cost with projected avoidance of customer interruption numbers or minutes in prioritizing distribution upgrade projects. *(Recommendation No. 4.3)*

Hydro does not employ a direct comparison of project cost versus avoided customer interruption numbers and minutes in ranking potential projects. Other utilities commonly include such a metric in prioritization protocols. They frequently base estimates of avoided customer interruption numbers and minutes on the numbers and minutes that would have been prevented over a recent study period (*e.g.*, the past five years) had the proposed project been in service over that period.

4.8. Despite a structured process for prioritizing projects, it is not clear that Hydro sufficiently emphasizes SAIFI and SAIDI. *(Recommendation No. 4.4)*

Hydro capital project planning methods employ twelve scoring criteria. It is not clear, that these criteria sufficiently focus on reliability performance. The terminal station equipment failures occurring in January 2014 and the atypical and increasing transmission and distribution SAIFI and SAIDI metrics since 2010 support the concern about such focus.

Planning

4.9. Hydro plans its transmission and distribution systems for load growth and other technical constraints on an appropriate basis.

Hydro uses its and Newfoundland Power's annual five-year energy and demand forecasts. Hydro plans capital projects to provide capacity so as to prevent exceeding system component capacities and other technical constraints such as maintaining voltage, stability, and frequency consistent with its design criteria.

4.10. Hydro's distribution system planning criteria are also consistent with good utility practices.

4.11. Hydro's load flow, voltage, stability, interconnection, and short circuit studies are appropriate and consistent with good utility practices.

4.12. Hydro's Distribution Planning group provides those technical studies required to support the Transmission and Rural Operation staff.

4.13. Studies show that all transmission lines, terminal station transformers, substation transformers, and distribution feeders should operate within the limits of applicable equipment or N-1 transformer contingency ratings during the winter 2014/2015 peak demand.

Hydro's June 16, 2014 *Report on Terminal Stations* shows that relocation of the Holyrood T8 transformer from the Western Avalon – Holyrood 138 kV loop (to replace the failed 125 MVA T1 transformer at Sunnyside Terminal Station) will provide sufficient transformer capacity to support the Stony Brook – Sunnyside 138 kV loop without causing a transformer capacity issue for the Western Avalon – Holyrood 138 kV loop.

4.14. Hydro reports that it has completed the transmission and distribution planning actions identified in its Integrated Action Plan.

Design

4.15. Some of Hydro's 138 kV transmission circuits and nearly all of its 66/69 kV transmission circuits on the Island Interconnected System are radial, causing customer outages for forced and planned circuit outages.

Note, however, that Hydro supplies Newfoundland Power and industrial customers by redundant lines. Five 138 kV transmission lines (TL239, TL259, TL241, TL244 and TL256) form the radial 138 kV transmission system along the Great Northern Peninsula (GNP). Three 66 kV transmission lines (TL226, TL227 and TL262) between Deer Lake and Peters Barren operate as radial transmission lines out of Deer Lake, Berry Hill and Peters Barren. Hydro, can, however, connect them to assist in supply of the northern portion of the GNP, should either TL239 or TL259 be out of service. Hydro owns and operates sixteen 66/69 kV transmission lines on the Island Interconnected System. With the exception of 66 kV transmission line TL225 between Deer Lake Power and Deer Lake Terminal Station, all of Hydro's 66/69 kV transmission lines operate radially under normal conditions. As noted above, three 66 kV transmission lines (TL226, TL227 and TL262) provide a 66 kV transmission path underlying the 138 kV transmission lines TL239 and TL259 on the GNP.

4.16. Hydro has built its transmission lines and distribution feeders in excess of Canadian Standards Association (CSA) Overhead Systems criteria and in conformity with good utility practice.

Hydro built its distribution feeders consistently with CSA standards. Hydro built its transmission lines to comply with CSA standards with an overload factor of 2.0.

4.17. Hydro uses IEEE Standard transmission and distribution conductor and transformer capacities for planning and operating its electric systems, which conforms to good utility practices.

4.18. Hydro allows limited temporary overloading of its transmission lines and its terminal station transformers, but limiting the "hot spot" temperature to 110°C appears to be unduly conservative.

Transformers generally should not be operated in excess of the manufacturer's nameplate ratings frequently. Nevertheless, good practice includes identifying the amount of overloading that can be tolerated under specific ambient conditions without producing more than minimal loss of transformer life based. The IEEE Guide for Loading of Oil-Immersed Power Transformers C57.91-1995 provides a useful guideline. Hydro reported that a study is underway to update practices for operating power transformers in excess of nameplate ratings.

4.19. Hydro has incorporated redundancy (N-1 contingency) in its transmission lines and terminal station buses consistent with the needs of the system. Rather than maintaining a spare 125 MVA transformer, it however depends on its N-1 transformer contingency designs to maintain system loads in case of a transformer failure. *(Recommendation No. 4.5)*

Hydro does not maintain a ready spare for its 125 MVA transformers for its Deer Lake to Stony Brook 138 kV Loop and its Stony Brook to Sunnyside 138 kV Loop.

4.20. Hydro does not have SCADA monitoring or control on three 66 kV transmission circuits and fourteen of its fifty-two terminal stations; it has SCADA control for only ten of its thirty-five distribution substations. *(Recommendation No. 4.6)*

Hydro does not have SCADA control and monitoring for three 66 kV transmission circuits and fourteen terminal stations. The absence of SCADA at the fourteen terminal stations does not affect the transmission system, but these terminal stations directly supply distribution customers. Hydro depends on indirect monitoring of these circuits and terminal stations on other circuits and terminal stations, and on customer outage reports. Good utility practice calls for full SCADA implementation on both transmission and distribution systems. This capability permits full monitoring of the systems, and can reduce customer minutes of interruption and SAIDI caused by the delay in dispatching trouble responders to terminal stations and substations.

4.21. Practices for transmission system raptor protection, lightning protection, and galloping conductor prevention have conformed to good utility practices.

4.22. Few Hydro distribution substations have multiple transformers and only some of the feeders can be tied to other feeders, which typifies rural distribution systems in our experience.

4.23. Hydro's distribution lightning protection, its use of downstream reclosers, and its distribution power system studies were consistent with good utility practices. However Hydro does not install animal guards on its distribution substation or feeder equipment. (*Recommendation No. 4.7*)

4.24. Hydro is currently updating its transmission Geographic Information System (GIS) data. Currently, its GIS, which contains all data related to its assets for its transmission system is only about 65 percent up to date. It should continue with updating not only its transmission equipment data, but also its distribution equipment data.

Protective Relaying

4.25. Protection and Control staffing is appropriate.

Hydro added staff (two technologists) in 2014 and a part-time technologist for 2014 and 2015 to complete non-recurring work associated with making improvements.

4.26. Protective relay scheme designs conform to good utility practice.

Improvement has resulted and will continue as a result of replacement of obsolete relays and changes to relay settings based on past studies. Hydro will be able to conduct a more thorough evaluation after completion of the in-process new protection standard.

4.27. Relay testing cycles conform to good utility practice and backlogs are reasonable.

4.28. Hydro uses an industry standard software package for conducting short circuit currents and relay coordination studies.

4.29. Protection and Controls personnel have appropriate involvement with investigations of relay scheme malfunctions.

4.30. Hydro has resumed replacement of obsolete electromechanical relays.

Hydro had previously done so, but did not continue the practice from 2011 through 2013. It is replacing, or planning to replace, relays in 2014 through 2018.

4.31. Hydro has reported progress in completing the 2014 Integrated Action Plan items involving protection and control; however, some have been delayed, as noted earlier in this chapter.

E. Recommendations

Reliability

4.1. Investigate and report on methods that can reduce Planned T-SAIDI. *(Conclusion No. 4.1)*

It may be possible to reduce customer impacts from planned radial 66 kV and 138 kV transmission line outages by installing more sectionalizing, by using more portable generation, or by incorporating hot working methods.

4.2. Analyze and report on the benefits of a dedicated capital program component dedicated to addressing the previous year's 10 to 15 percent worst performing feeders. *(Conclusion No. 4.6)*

Worst performance should comprise the only criterion for qualification in this component. A combination of SAIFI and SAIDI should apply in identifying worst performing circuits. This should be a Level 1 program (*i.e.*, not subject to alteration based on prioritization involving other capital program components). Hydro should report on the results of this analysis and propose a program with defined dimensions (*e.g.* numbers of circuits, expenditure levels) by July 1, 2015.

4.3. When prioritizing reliability projects, include a factor that relates cost to anticipated avoided customer interruption numbers and minutes. *(Conclusion No. 4.7)*

Hydro should report on the results of this analysis and propose a means for addressing this cost/benefit metric by July 1, 2015.

4.4. Increase the weighting given to resulting SAIFI, SAIDI, and numbers of customer interruptions and minutes when prioritizing proposed project. *(Conclusion No. 4.8)*

Hydro should report on the results of this analysis and propose a means for incorporating a weighting increase by July 1, 2015.

Planning

Liberty has no transmission and distribution system planning recommendations.

Design

4.5. Perform a structured analysis of the costs and benefits of maintaining a spare for the 125 MVA transformers, considering age and equipment condition and the recent failures of the T1 transformer at Sunnyside Terminal Station and the T5 Transformer at Western Avalon Terminal Station. *(Conclusion No. 4.19)*

4.6. Conduct a structured analysis of expanding the SCADA system to include more and perhaps all distribution substations, in order to reduce customer minutes of interruption, and to reduce SAIDI. *(Conclusion No. 4.20)*

4.7. Apply animal guards at distribution substations when conducting maintenance work in the substations. *(Conclusion No. 4.23)*

Protection and Control

Liberty has no protection and control recommendations.

V. TRO Asset Management

A. Background

Liberty's Interim Report found that one of the principal causes of the January 2014 outages was transmission equipment failures with the number and nature of the failures raising questions about Hydro's operation and maintenance of equipment. Liberty found that Hydro did not complete recommended maintenance on the equipment that failed and that protective relay design issues and insufficient operator knowledge of the protective relay scheme were contributing circumstances to the transmission equipment failures. Liberty made sixteen recommendations outlining actions for Hydro to take to address these issues:

1. Intensifying dissolved gas analysis of critical transformers
2. Catching up on overdue testing and maintenance on critical transformers
3. Completing studies to verify that planned relocation of the repaired T5 transformer to Sunnyside transformer will not unduly reduce reliability
4. Exercising air blast circuit breakers in 2014
5. Catching up on overdue testing and maintenance on critical air blast circuit breakers
6. Accelerating the air blast circuit breaker preventive maintenance cycle
7. Periodically operating circuit breakers from protective relays
8. Redesigning breaker failure relay protection schemes for certain configurations
9. Formally examining installation of breaker failure relay protection for transformers not already protected
10. Completing studies being conducted to determine whether abnormal system disturbances could have caused the T5 transformer failure at Western Avalon terminal station
11. Seeking to locate for Western Avalon T5 a replacement transformer for potential purchase
12. Including experienced protection and control technologists with station-event response teams, and modifying complicated protective relay schemes
13. Not employing "slow trip" coils where used by backup relay tripping in its air blast circuit breakers
14. Preparing a maintenance practices document addressing the new procedure for applying protective coatings to air blast circuit breakers
15. Reviewing substation and protection and control staffing needs
16. Using qualified substation contractor personnel to assist with the transformer projects and to catch up with regular scheduled maintenance on transformers and circuit breakers.

The Board in its Interim Report accepted Liberty's recommendations, and directed Hydro to undertake a number of actions, including the filing of progress reports, to implement the recommendations. Liberty as part of its work leading to this report examined Hydro's overall approach to asset management and the actions Hydro took to implement both Liberty's recommendations and the Board's directions. This chapter addresses Liberty's investigation of asset management for transmission assets and the progress Hydro has made in implementing the recommendations in the transmission area.

Hydro's Transmission and Rural Operations ("TRO") organization has responsibility for the management of its transmission and distribution assets, with support from Nalcor's Project

Execution and Technical Services organization. Liberty reviewed Hydro's TRO asset management execution. Liberty's examination included practices for maintaining and enhancing the condition and reliability of transmission lines, substation equipment, distribution feeder poles, and other line equipment. Liberty assessed the adequacy of vegetation management practices. Our review included the accountability for work completion, staffing levels, training, succession planning, and the maintenance management tracking methods used to execute asset management strategies and meet goals and targets fully and efficiently.

B. Chapter Summary

Hydro's inspection programs and practices for identifying condition issues on transmission and distribution systems and on terminal stations conform to good utility practices. Preventive and corrective maintenance procedures also conform to good utility practices, but Hydro has not succeeded in executing some activities on a timely basis in recent years. Backlogs in such work have resulted at least in part due to the diversion of resources to perform other, emergent work and to difficulties in taking planned outages on radial facilities, whose maintenance can produce long customer outages.

These backlogs raised concern about the sufficiency of skilled resources to complete maintenance work, given other work priorities. Some backlogs had been accumulating year over year. Hydro has more recently increased efforts to reduce its backlog of planned preventive maintenance and corrective maintenance work orders, by applying short-term tracking, monitoring and accountability methods, and by providing more resources to the work. Hydro should develop a comprehensive plan to bring maintenance backlogs to a more appropriate sustained level.

Due to the advanced age of much of Hydro's transmission and distribution equipment, substantial levels of maintenance and replacement will be required, including more intense inspections, maintenance and modernization programs.

Hydro has steadily increased capital investments dedicated to its transmission and distribution systems. We observed a dramatic investment increase in 2014. Chapter IV (*TRO System Planning and Design*) addresses our remaining concern about capital investment. Recommendation No. 4.4 from that chapter addresses the need for Hydro to address how its methods for prioritizing proposed capital projects give weight to improvement in reliability metrics (such as SAIFI and SAIDI).

Liberty's recommendations and the Board's directions from their 2014 Interim Reports were incorporated into an Integrated Action Plan, along with other actions Hydro identified. This Plan included a number of activities related to Hydro's transmission and distribution systems. Hydro has focused substantial attention and resources to address the Interim Report recommendations including addressing the deferred transformer and air blast circuit breaker maintenance and to repair or replace power transformers that failed during the January 4, 2014 outage. It will take a number of years for Hydro to complete all necessary activities affecting transmission and distribution. Hydro should demonstrate that its efforts for improving work order completion performance are actually reducing its annual backlogs of preventive maintenance and corrective maintenance work activities.

C. Findings

1. TRO Asset Management Organization

Hydro's Transmission and Rural Operations group develops long-term transmission and distribution asset plans. They also prepare annual and weekly asset inspection and maintenance work plans and schedules, conduct asset inspections, and perform corrective and preventive maintenance activities. They follow the common approaches and practices developed under Nalcor direction, as discussed in Chapter III.

a. Skilled Workers

Line Workers conduct inspection, maintenance, and construction work on Hydro's transmission and distribution substations and lines. Substation Electricians and Operators conduct maintenance on Hydro's terminal stations. They also provide assistance with gas turbine maintenance work. Substation Electrical Maintenance Workers perform electrical inspection and maintenance work, testing, and troubleshooting of terminal stations. They do the same for hydraulic and thermal plant equipment and they perform switching and isolation of high voltage equipment. Mechanical Maintenance Millwrights/Heavy Duty Mechanics perform Hydro's mechanical maintenance, troubleshooting, testing, installation, assembly, and modification of thermal, diesel, and hydraulic plant equipment. The next table provides the numbers of skilled workers, which stand at just over 3 percent less than 2009 levels.[80]

Table 5.1 Full-Time Equivalent Skilled Workers

Classification	2009	2010	2011	2012	2013
Transmission Line Worker A	23	23	23.5	22.5	23
Distribution Line Worker A	42.5	42.5	41.5	40.5	40.5
Substation Electrician/Operator (Gas Turbine)	2	2	2	2	2
Substation Electrical Maintenance A	13.5	13.5	13.5	13.5	13.7
Mechanical Maintenance A – Millwright/Heavy Duty Mechanic	3	3	3	2	2
Total Skilled TRO Workers	**84**	**84**	**83.5**	**80.5**	**81.2**

Hydro[81] primarily uses full time employees to complete the corrective and preventative maintenance work, including emergency repairs. It uses combinations of employees and contractors to perform capital work, including the accelerated air blast breaker replacement program. Contractor resources perform the predominant share of capital work for Hydro.

Line contractors regularly perform new construction and upgrade work. Hydro uses employees for inspection work, however. [82] Line contractors supplement employee workers in emergency situations (*e.g.*, responding to storm damage), in order to reduce the time required to complete

[80] Response to RFI #PUB-NLH-106.
[81] Response to RFI #PUB-NLH-345.
[82] Response to RFI #PUB-NLH-362.

repairs. Hydro has used Newfoundland Power's line workers in response to trouble calls, in cases where Hydro does not have the resources to do so in a timely manner.

Hydro determines its FTE employee requirements during an annual work planning and budgeting process. When completing 2014 budgeting work in 2013, Hydro included an additional Protection and Control position, and planned to add additional temporary resources as required for the capital program. Following the January 2014 events, Hydro added additional temporary resources to enable it to complete all work identified arising from the review of the January 2014 events and scheduled for completion this year.

Hydro has recently completed a review of the resources required to complete the 2015 annual maintenance plan, to address accelerated breaker and power transformer maintenance, and complete the 2015 capital program. This work is expected to require a further increase in resource numbers.

2. Equipment Age

Equipment age comprises a major factor in determining equipment maintenance and replacement needed to maintain reliability. Hydro operates a system with a high amount of aged components.[83] On the transmission system, about 65 percent of its transmission tower lines, 45 percent of its transmission pole lines, and 33 percent of its wood transmission poles exceed 40 years of age. Sixty-seven percent of Hydro transformers have been in service more than 30 years and 38 percent have served more than 45 years. One hundred percent of Hydro's 138 kV and 230 kV air blast circuit breakers have been in service more than 30 years and 82.5 percent have been installed more than 40 years.

On the distribution system, about 28 percent of[84] wood distribution poles are over 40 years old, about 83 percent of its distribution feeders are over 40 years old, and about 47 percent of its distribution substation transformers are over 40 years old.

3. Inspection and Maintenance Scheduling, Tracking, and Monitoring

a. Planning and Scheduling

An annual plan directs preventive and corrective maintenance, project work, and training. The annual plan drives monthly and weekly schedules, and provides the baseline for managing planned and emergent work.[85] The team enters plan details into the Computerized Maintenance Management System ("CMMS"). The team evaluates job completion progress against the plan as the year progresses, and makes adjustments to keep it achievable and focused on priorities.

Hydro monitors and tracks work completion at monthly and annual levels. Hydro's Project Execution Project Managers provide monthly progress reports on capital project cost and quality

[83] Response to RFI #PUB-NLH-335.
[84] Response to RFI #PUB-NLH-356 and 357.
[85] Responses to RFIs #PUB-NLH-166 and 174.

to the Regional Managers. The reports address project scope, schedule, cost and quality. They review work lists to confirm full completion.

For inspection and maintenance work, Short Term Planning and Work ("STPW") Supervisors issue 7-day and 30-day schedules to Regional Work Execution Supervisors. The documents schedule work that includes planned activities and critical emergent corrective maintenance work. Regional Work Execution Management reviews progress against the weekly plans when developing schedules for the coming week. The Planners determine resource, material, tool, and equipment needs for scheduled work.

Hydro's Regional Managers provide direct oversight over preventive and corrective maintenance repair work. They prepare recovery plans when work falls behind schedule. Regional Planning Groups prepare weekly schedules for periodic inspection of transmission, distribution, terminal station, and substations. Regional Work Execution Supervisors ensure completion of the scheduled inspection work.

The Work Execution Group reviews all new corrective maintenance work orders for prioritizing and planning purposes. The Short Term Planning and Scheduling (STPS) Group identifies resources needed for each corrective maintenance item. These jobs get placed on a "waiting to be scheduled" status after required materials arrive.

The STPS Group[86] generates preventive maintenance work orders in the computerized management system. Regional Planners enter these orders into weekly schedules. Paper copies of the work orders and paper check sheets document work activities. Supervisors review and sign off completed work orders and check lists. Completed, signed-off work orders go to an office clerk, who keys information into the computerized management system. The clerk also scans the work order and the associated check sheets. All PM completed work orders and check lists are also sent to an Asset Specialist who then reviews the document package for all completed work orders.

b. Overall Work Tracking

Hydro[87] monitors its maintenance and project work orders backlog via its Computerized Maintenance Management System. Hydro's asset management strategy includes performance metrics used to measure work performance (*e.g.*, percentage of work orders completed compared to weekly and annual work plans). Monthly meetings address work completion results versus plans rates. Management uses the past year's completion and backlog rates as a baseline for developing the following year's annual work plan.

Hydro continued for 2014 a target of completing 75 percent of the work orders per the weekly schedule, or a 10 percent improvement over 2013 weekly rates. The next table shows completion rates for the prior two years.[88]

[86] Response to RFI #PUB-NLH-174.
[87] Responses to RFIs #PUB-NLH-155 and 156.
[88] TRO Central data includes Hardwoods and Stephenville Combustion Turbines data.

Table 5.2: Weekly Work Completion

Area	2012	2013	Target
TRO Central	57%	**55%**	>75%
TRO North	66%	**66%**	>75%

Hydro has a strategy to improve scheduled work plan compliance by reducing unplanned reactive emergent work caused by weather, equipment failures, and other issues. Although not all reactive emergent work can be prevented, Hydro tasks its Root Cause and Repeat Failure Analysis Council to identify and address significant, but controllable, causes of emergency work orders.

Hydro also tracks average weekly emergency work load, in terms of percentage of all work, measuring it against an anticipated rate of 10 percent or less. The Central region has been meeting the target, but the Northern has not, as the following table demonstrates.[89]

Table 5.3: Percentages of Emergency Work

Area	2008	2009	2010	2011	2012	2013	Target
TRO Central	10%	8%	9%	9%	9%	10%	<10%
TRO Northern	20%	16%	15%	18%	16%	**17%**	<10%

Hydro[90] monitors annual preventive work completion versus the annual work plan, targeting 2014 completions at 80 percent (*i.e.*, a 20 percent backlog). The next table shows that both regions[91] have been meeting the overall completion target.[92]

Table 5.4: Preventive Maintenance Work Order Completions

Area	2008	2009	2010	2011	2012	2013	Target
TRO Central	94%	78%	88%	82%	85%	87%	>80%
TRO Northern	n/a	n/a	n/a	93%	98%	99%	>80%

c. Electronic Access to Data

All terminal station control rooms provide electronic access to the Computerized Maintenance Management System and other corporate applications.[93] This access permits ready access to the most recent data (*e.g.*, work order history) during terminal station inspections. Network Services, Protection and Control and Distribution Services Technologists have laptop computers. Also, Hydro uses handheld computers equipped with geographic information system capability in the conduct of its transmission Wood Pole Line Management program (discussed in the immediately following subsection). Hydro also has underway a pilot testing of the use of handheld computers with geographic information system capability in performing distribution and substation

[89] TRO Central data includes Hardwoods and Stephenville Combustion Turbines data.
[90] Response to RFI #PUB-NLH-155.
[91] TRO Central data includes Hardwoods and Stephenville Combustion Turbines data.
[92] TRO Central data includes Hardwoods and Stephenville Combustion Turbines data.
[93] Response to RFI #PUB-NLH-358.

inspections. Hydro is also considering an Outage Management System and will use the pilot project results to evaluate its options.

Hydro does not, however, employ a mobile application that provides crews with electronic work orders and check sheets. Hydro is, however, exploring options that will support mobile applications. Crews use paper work orders and check lists to report inspection work completed, defects identified, and requests for corrective maintenance. Inspectors return completed paper work orders to supervisors, who verify work completion and review corrective maintenance requests. Regional office clerks enter corrective maintenance work orders, per requests indicated on work order or inspection forms, without priority into the computerized maintenance management system.

d. Condition Assessments

Hydro[94] assesses the condition of transmission, terminal station, substation, and distribution line assets by a combination of preventive maintenance inspection and testing, the wood pole line management ("WPLM") program, and use of outside consultants.

The Front Line Supervisor and then Long Term Asset Planning ("LTAP") review preventive maintenance work orders. Inspection results and equipment electrical tests undergo analysis intended to identify candidate areas for rebuild plans. When inspections identify deficiencies, repair work orders are issued on a priority basis to address them.

The transmission pole inspection and treatment program relies upon review by Long Term Asset Planning and Project Execution and Technical Services personnel. They review and address weak poles through refurbishment plans that have a priority basis. Refurbishment work is included in annual work plans. Hydro also uses outside consultants to assess assets, based on data that includes electrical and oil test results, asset failure trends, and asset age and industry experience. An example is the current assessment being carried out on thirty of Hydro's power transformers.

4. Transmission Lines and Poles

Hydro's[95] 57 transmission lines contain 3,509 kilometers of lines. Hydro maintains the condition of its transmission lines and poles under a preventive maintenance program (which includes periodic line inspections), a corrective maintenance program that addresses identified repair needs, and a capital transmission line repair and upgrade program.

Hydro conducts transmission system inspections from helicopters on semi-annual cycles. It conducts ground inspections by foot or from snowmobiles on annual cycles. Hydro inspects steel transmission line structures on a ten-year cycle. Inspectors (line workers) conduct climbing inspections of steel and ground inspections of anchors and footings on one tenth of the towers on each steel tower line each year. Hydro has conducted infrared (thermographic) inspections on

[94] Response to RFI #PUB-NLH-368.
[95] Responses to RFIs #PUB-NLH-085, 101, 172, and 175.

transmission system connecting hardware since 2010. These inspections examine switches, splices, and jumpers.

Hydro[96] justifies transmission system and wood pole line preventive maintenance activities using Value Based"™ RCM ("Reliability Centered Maintenance"). Power Systems Solutions International from Calgary guided a Hydro review of the transmission maintenance program using Value Based RCM in 2003. The value based approach comprises a systematic, objective, well documented approach to maintenance optimization. The approach employs accepted risk assessment concepts. It also permits a monetary comparison of the costs and benefits of maintenance activities and programs. Hydro has since continued to advance its maintenance program through the use of asset criticality rankings, updated information from manufacturers, maintenance practices of others, and analysis of asset performance data.

Hydro[97] has about 23,350 wood transmission poles. Hydro implemented what is now a 20-year Wood Pole Line Management program in 2005. Older wood transmission poles have developed internal cracks and hollow areas, which visual inspections cannot detect. The program seeks to identify those poles over 20 years old that do not meet strength criteria. The program's inspections, tests, removals, and treatments work complements the semi-annual and annual transmission line inspection program.

Pole inspection and testing practices include detailed visual pole and pole equipment inspections. A check list governs them. The inspections examine for deteriorated conditions, provide for tightening loose bolts, and sound for hollow areas. Hydro uses digital Transmission Line Management Detailed Field Forms, which, after testing and any re-treating,[98] electronically transfer to a central database for review by the Transmission Asset Specialists. These specialists examine the forms as part of efforts to identify and prioritize potential pole replacement projects.

Cold weather reduces the threat of decay below ground level. Hydro inspections therefore had not included excavating around poles. Hydro began to do so in 2014, with boring, measuring, and inserting boron rods below ground line on every tenth pole. Hydro has also this year equipped transmission line crews and transmission specialists[99] with digital cameras to enable close-up photographs for assessing the condition of hardware components.

Hydro has replaced about 265 transmission wood poles (1.14 percent of the total) over the past five years.[100] Hydro does treat its wood transmission poles to extend life, but the Company expects that it will likely need to accelerate its rate of replacement.[101]

96 Response to RFI #PUB-NLH-349.
97 Responses to RFIs #PUB-NLH-085, 088 and 172.
98 Response to RFI #PUB-NLH-085.
99 Response to RFI #PUB-NP-168.
100 Response to RFI #PUB-NLH-088 and 095.
101 Response to RFI #PUB-NLH-374.

The next table summarizes expenditures[102] for inspecting and replacing transmission wood poles from 2009 through 2013 under the Wood Pole Line Management Program. Transmission pole inspection costs fell slightly in 2013, but transmission pole replacement costs increased.

Table 5.5 Transmission WPLM Program Costs ($ thousands)

Year	Inspection Costs	Replacement Costs
2009	$713	$1,590
2010	$1,193	$1,309
2011	$779	$1,440
2012	$770	$1,149
2013	$613	$1,768

The next table lists[103] O&M expenditures for steel and aluminum transmission towers expenditures.

Table 5.6: Steel and Aluminum Tower O&M ($ thousands)

Year	Cost
2009	$125
2010	$132
2011	$117
2012	$135
2013	$287

Hydro[104] has been tracking transmission line inspection work orders. The next tables show the numbers scheduled and completed in recent years.

Table 5.7: WPLM Wood Pole Inspections

Item	2011	2012	2013
Scheduled	1,659	1,286	2,070
Completed	1,659	1,286	2,070
Percent Backlogged	0%	0%	0%

Table 5.8: Steel and Aluminum Tower Inspections

Item	2011	2012	2013
Scheduled	44	43	45
Completed	44	43	45
Percent Backlogged	0%	0%	**0%**

The next table shows corrective maintenance backlogs for transmission line equipment.[105] They fell far short of targets. Hydro actually had more orders backlogged than completed in the past two years.

[102] Response to RFI #PUB-NLH-353.
[103] Response to RFI #PUB-NLH-353.
[104] Response to RFI #PUB-NLH-373.
[105] Response to RFI #PUB-NLH-087.

Table 5.9: Transmission Line Corrective Maintenance Backlogs

Work Orders	2011	2012	2013	Target
Completed	292	216	120	
Backlogged	184	249	178	
Percent Backlogged	38.7%	53.5%	**59.7%**	<25%

Hydro described about 33 percent of the backlogged corrective orders as low priority jobs.

5. Distribution Equipment

Hydro's[106] distribution systems contain 2,650 kilometers of line.[107] Hydro inspects overhead distribution lines and equipment, including underground riser poles, on frequencies ranging from five years to ten years. Hydro has no distribution wood pole program corresponding to the one applicable to transmission poles.[108] A Distribution Maintenance Committee, in consultation with the Operations staff in each region, determines line inspection plans, based on age, wind and salt exposure, and known line performance issues. A contractor performs diving inspections on its submarine cables, generally every three years.

Distribution line workers also use the paperwork order and inspection checklist process in a manner similar to that applicable to transmission facilities. Subsequent repair work is handled similarly as well.

The next table summarizes recent O&M expenditures for distribution line inspections.

Table 5.10: Distribution Line Inspection Costs

Region	2009	2010	2011	2012	2013
Central	$9,430	$25,675	$20,154	$63,260	$97,367
Northern	8,500	8,959	6,324	21,742	23,439
Totals	**17,930**	**34,634**	**26,478**	**85,002**	**120,806**

The next table shows capital expenditures for distribution line rebuild projects, including pole replacements. Those expenditures have increased considerably since 2009.

Table 5.11: Distribution Pole Replacement Costs ($ thousands)

Region	2009	2010	2011	2012	2013
Central	1,688	1,790	2,351	3,562	4,338
Northern	1,652	1,304	3,123	3,283	2,719
Totals	**3,339**	**3,094**	**5,474**	**6,845**	**7,057**

[106] Responses to RFIs #PUB-NLH-092 and 175.
[107] Response to RFI #PUB-NLH-101.
[108] Response to RFI #PUB-NLH-352.

Hydro's TRO[109] inspects its 79 distribution lines on the Island Interconnected System on frequencies ranging from five to ten years. Forty-eight are fed from terminal stations, including 25 lines in the Central Region and 23 lines in the Northern Region. The remaining 26 distribution lines are fed from 26 distribution substations, all in the Central Regions. Hydro's inspection criteria set lines and substation completion targets of 90 percent. Hydro[110] conducted the numbers of distribution line inspections as indicated in Table 5.12, below.

Table 5.12: Distribution Line Inspections

Year	Inspections			
	Scheduled	Completed	Rate	Target
2011	154	121	79%	90%
2012	145	135	93%	90%
2013	127	121	95%	90%

Scheduled inspections differ in number each year. For example, one of the main drivers is exposure due to severe weather. A number of factors influence the completion of scheduled inspections during the year, such as equipment failures, line trouble, customer issues, adverse weather, and service extension and upgrade work. These factors in some instances can lead to the reprioritization of scheduled inspections and deferrals to the following year. Hydro targets inspection completion for lines and substations at 90 percent.

Hydro indicated that the number of inspections scheduled varies from year to year since not all distribution lines are inspected at the same frequency. One of the main drivers that dictates frequency is environmental exposure due to severe weather. Hydro replaced 2,850 of its 46,790 distribution poles (6 percent) in the past five years.[111]

Hydro has had[112] few maintenance work orders for distribution substations. Trending the percentage of backlogged orders is therefore not informative. However, the number of distribution preventive maintenance work orders in backlog increased from 1 in 2012 to 7 in 2013. The number of corrective maintenance work orders in backlog has been increasing. As with some transmission work, backlogged items include non-critical work deferred to times when Hydro can minimize customer interruptions during maintenance work.[113]

Distribution line work orders are more substantial in number. Their backlogs have increased substantially since 2011. Hydro indicated that about 26 percent of backlogged preventive maintenance orders and 14 percent of corrective ones involve low priority jobs. Backlogged corrective maintenance orders increased about 20 percent each year from 2011 to 2013. The next tables show the growth in backlogged distribution line orders.[114]

[109] Response to RFI #PUB-NLH-175.
[110] Response to RFI #PUB-NLH-377.
[111] Response to RFI #PUB-NLH-095.
[112] Response to RFI #PUB-NLH-171.
[113] Response to RFI #PUB-NLH-091.
[114] Response to RFI #PUB-NLH-094.

Table 5.13: Distribution Line Preventive Maintenance Backlogs

Work Orders	2011	2012	2013	Target
Completed	744	859	979	
Backlogged	46	90	188	
Percent Backlogged	5.8%	9.5%	16.1%	<25%

Table 5.14: Distribution Line Corrective Maintenance Backlogs

Work Orders	2011	2012	2013	Target
Completed	1215	1138	1063	
Backlogged	262	354	454	
Percent Backlogged	17.7%	23.7%	29.9%	<25%

6. Vegetation Management

Hydro applies its vegetation management program to transmission and distribution systems, their access trail networks, facilities, yards, penstocks, dams, and approximately 300 kilometers of forest access roads.[115] Three vegetation control inspectors report to the Vegetation Control Specialist, who in turn reports to the Transmission and Rural Operations Services Manager.

The Vegetation Control Specialist conducts overall planning, implementation and funding allocation under the vegetation control program. The Specialist also manages the vegetation management contracting and billing processes as well. The Specialist interfaces with Hydro's Environmental Services Department and external provincial and federal agencies that deal with environmental and natural resources issues.

Hydro typically limits more expensive tree trimming (versus removal) to distribution systems, but trims on a few transmission line rights-of-ways. Trimming typically provides only short-term (two to three year) maintenance of required clearances. Brush control comprises the largest portion of Hydro's program. Crews of 10 to 12 generally carry out brush control activities. They work primarily on transmission (where single events can have widespread outage consequences) and secondarily on distribution circuits. The conductor clearances that guide trimming comprise: (a) 15 feet for 230 kV, (b) 13 feet for 138 kV, (c) 10 feet for 69 kV, (d) 1.8 meters for distribution primary conductors, and (e) 90 centimeters for secondary and neutral conductors.

Hydro addresses danger trees (those with the potential to contact lines through wind, falling, or arcing, due to proximity to conductors). Customer resistance comprises the most significant problem with danger trees along distribution circuits. Accessibility comprises the most significant barrier to addressing danger tree removal. Winter access by snowmobile can provide the most ready and least cost alternative. Last winter the Vegetation Management group implemented a winter danger tree removal program employing inspectors accompanied by contractor cutting staff. Snowmobile patrolling produced the removal of about 1,000 danger trees.

[115] Response to RFI #PUB-NLH-359.

Transmission circuits with hardwood trees have a four-year clearing cycle. Those cycles extend to twelve or more years on circuits where conifer trees predominate. For distribution lines, the low end of the cycle range is about the same, but the high end of the range is only five to six years. This shorter duration reflects the consequences of narrow rights-of-way and distances from equipment to ground. Chemical spray programs for brush control in hardwood areas are done on seven to ten year cycles.

The Vegetation Management Specialist and the Asset Specialist have primary responsibility for regular annual aerial vegetation inspections. Vegetation Management inspectors conduct additional ground inspections during the winter. Crews also provide reports on vegetation as part of the transmission wood pole program and as part of climbing inspections.

Contractors perform all trimming, tree removal, and brush clearing work under Hydro's supervision. Generally, Hydro has access to between two and four contractor cutting crews. A contractor spray crew is available during the spray season to provide weed control at terminal stations, yards, and other locations.

The next table lists[116] O&M and capital expenditures for vegetation management in recent years.

Table 5.15: Vegetation Management Expenditures ($thousands)

Year	O&M	Capital
2009	$1,262	$111
2010	$1,383	$14
2011	$1,493	$7
2012	$1,818	$3
2013	$2,032	$42
2014	$2,576	$55

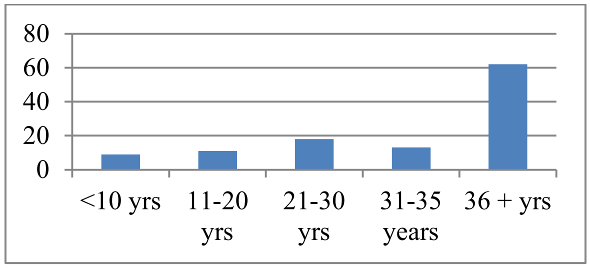
Hydro backlogged 146, 177, and 187 vegetation-related corrective items in 2011, 2012, and 2013, respectively, completing the work during following summer and fall seasons.

7. Terminal Stations

Hydro's[117] 57 terminal stations employ 105 transformers. Sixty-seven percent of Hydro transformers have been served for more than 30 years, with the service lives of 38 percent exceeding 45 years. The next chart lists the distribution of Hydro's power transformers, by age.

[116] Response to RFI #PUB-NLH-359.
[117] Responses to RFIs #PUB-NLH-098, 169, 174, and Hydro Report to the Board - Install Transformer On Line Monitoring; July, 2014.

Chart 5.16: Transformers by Age Group



Hydro[118] conducts general inspections of its 57 terminal stations on cycles of 120 to 180 days. Maintenance personnel familiar with the equipment involved use equipment-specific forms.

Six year cycles apply for major preventive maintenance and testing of oil and the insulating medium sulfur hexafluoride (SF_6). These procedures, based on manufacturer and Hydro equipment engineer recommendations, conform to good utility practices. Hydro conducts preventive maintenance activities on the compressed air systems of air blast circuit breakers on monthly and annual cycles. It performs oil condition ranking tests on oil circuit breakers on three-year cycles.

Hydro[119] has been conducting dissolved gas analysis testing on each terminal station and generator step-up unit transformers at least annually. Dissolved gas and particle count analysis at on-load tap changers occurs on 3-year cycles. Hydro had been conducting quarterly dissolved gas analysis on three of its most critical transformers. Subsequent to the January 2014 transformer failure events, as recommended by Liberty, Hydro conducted a condition assessment of its transformers. This assessment led Hydro to begin such testing on three other transformers, which exhibited gas levels.[120] A 2014 transformer criticality ranking study led to plans to install dissolved gas monitors on seven critical terminal station and step-up transformers by November, and on others later.[121] The planned devices will give system operators nearly real-time knowledge of dissolved gas levels in the oil of the most critical transformers.

Terminal stations also undergo major preventive maintenance and testing on planned six-year cycles, which Hydro has developed on the basis of manufacturer and Hydro equipment engineer recommendations. They conform to good utility practices. Hydro expanded power-factor testing (formerly limited to 230 kV transformers) to all terminal station transformers in 2013. As with air blast circuit breakers, Hydro also stopped deferring six-year maintenance work on transformers. The Liberty 2014 Interim Report recommended acceleration of such maintenance work. Hydro has been working to bring all work back within schedule by the end of 2015. Hydro conducts detailed inspections, maintenance, and tests on its terminal station disconnect switches, instrument transformers, capacitor banks, and protective relays on six-year cycles.

[118] Response to RFI #PUB-NLH-364.
[119] Response to RFIs #PUB-NLH-169 and 174.
[120] Hydro Report to the Board - Regarding Work to be Performed on Transformers; June 2, 2014.
[121] Hydro Report to the Board - Install Transformer On Line Monitoring; July 2014.

Hydro has not been meeting the six-year cycle for its 105 power transformers (66 kV to 230 kV) for some time.[122] By the beginning of 2014, Hydro had completed deferred maintenance on 64 transformers. Hydro accelerated maintenance this year. Using a criticality scoring method, it plans to bring all testing and maintenance up to date by the end of 2015. Plans call for completion this year of work on 28 power transformers, 8 of which are behind schedule. Hydro plans to complete work on 23 more in 2015. Eight of those are also overdue for maintenance work. To remain on schedule from 2016 forward, Hydro plans to complete work on 17 or 18 transformers each year.

In addition to preventive maintenance, effective asset management requires prompt addressing of Corrective Maintenance items identified as other work proceeds. Following identification of such needs, the Work Execution group reviews, prioritizes, approves, and plans work execution. Work orders warranting completion within a week get placed into "backlog" as Priority 1 or 2 items.[123] Orders classified as Priority 3 Corrective Maintenance generally should be addressed in a month or so. Priority 4s are scheduled "as required." Actual practice, however, leads to delays in work below Priority 2, because taking equipment out of service for maintenance in some cases requires outages. Lower priority items are carried over until they can be completed, often during the next scheduled outage.

Hydro has monitored backlogs in terminal station corrective maintenance. The Company increased the use of temporary and contractor resources to address such work in 2014. This increase in resources will continue in 2015 as required to ensure completion of critical work, to keep the backlog stable, and to more promptly address increases in maintenance activity that result as equipment ages.

The next table presents total numbers of corrective work orders related only to electricity supply equipment in recent years.

Table 5.17: Terminal Station Corrective Maintenance

Year	Orders Generated	Current Orders Completed	Backlog Orders Completed	Total Orders Completed	Backlogged Orders
2011	604	382	177	559	88
2012	684	358	168	526	136
2013	590	406	180	586	187

Hydro has been replacing substantial amounts of terminal station equipment. The next table shows equipment replaced since 2004 and planned for replacement by 2019.[124]

[122] Hydro Report to the Board Regarding Work to be Performed on Transformers, June 2, 2014.
[123] Response to RFI #PUB-NLH-083.
[124] Response to RFI #PUB-NLH-099.

Table 5.18: Terminal Station Equipment Replacement

Equipment	Quantity Replaced	Planned Replacements
Surge Arresters	198	114
Battery Banks	31	7
Battery Chargers	32	9
Building/Grounds Improvements	15	4
Circuit Breakers (excluding ABCBs)	14	17
Compressed Air System Components	17	9
Line Relay Protection Upgrades	21	10
Breaker Failure Upgrades	-	6
Disconnect Switches	36	46
Instrument Transformers	72	139
Insulators, by site	36	10
Bushing Replacements, by Transformer	71	254
Transformer Radiator Replacements	5	11
Transformer Oil Replacements	2	5
Transformer Gasket Replacements	1	5
Transformer Replacements	2	5

8. Air Blast Circuit Breakers

Liberty's Interim Report addressed problems with the aged air blast circuit breakers that Hydro employs in terminal stations. The report made recommendations to address those problems. All 63 of Hydro's 138 kV and 230 kV air blast circuit breakers have served for more than 30 years, with 82.5 percent in excess of 40 years. Eleven are between 30 and 40 years old and 52 are between 41 and 50 years old.[125] Hydro's criteria had called for a six-year cycle of preventive maintenance for these breakers. Hydro[126] had been behind in this work since 2010.[127] The Company was diverting resources to work considered most critical work for supply reliability (*e.g.*, equipment failures, problems identified by testing and inspections, unexpected growth in resource requirements to perform capital projects).

As recommended by Liberty, Hydro accelerated the pace of maintenance on air blast circuit breakers in 2014, seeking to bring all work up to date by the end of 2015. Through the beginning of 2014, Hydro completed deferred work on 23 of the breakers. In 2014, Hydro accelerated its maintenance work, using a criticality scoring method. Plans call for completion of overdue testing and maintenance by the end of 2015. Plans for 2014 call for completion on 23 more of the breakers (9 are overdue). Plans for 2015 call for work on 17 more (none overdue). Thereafter, recognizing equipment age and recent air blast circuit breaker issues, Hydro will reduce the cycle to four years. This will require a completion pace of 9 to 10 air blast circuit breakers per year. However, Hydro plans to replace all of these breakers by 2020.

[125] Meeting with Hydro on 10 October 2014.
[126] Response to RFI #PUB-NLH-365.
[127] Hydro Report to the Board Regarding Work to be Performed on Air Blast Breakers, June 2, 2014.

Hydro also implemented in 2013 and modified in 2014, as recommended by Liberty, a procedure for annually opening and closing all 69 kV and above breakers from local controls and from the Energy Control Center. This "exercising" serves to clean auxiliary contacts and to verify operation of breaker mechanisms and trip-close control circuits.

9. Distribution Substations

Line personnel inspect Hydro's 26 distribution substations[128] about every 120 days.[129] The paper-based processes for inspection and follow-up used for inspections of other equipment apply to these facilities as well. Visual-only inspections of distribution substation and line hydraulic and electronic reclosers occur monthly, supplemented by the detailed 120-day inspections and some further annual inspection and testing. As needed testing may occur as well, triggered by the number of operations (duty cycles).

Specific procedures address the scope of 120-day, annual, and duty-cycle driven inspection and testing. Line personnel conduct monthly and 120-day inspections and three to five year operation and oil tests of substation and line voltage regulators. Hydro[130] conducts on six-year cycles electrical quality testing on substation transformers rated at 1.0 MVA and above.

10. Generation Maintained by Transmission and Rural Operations

The Transmission and Rural Operations[131] group operates and maintains Hydro's smaller diesel and gas turbine generating units. Prime power diesel generator inspections examine oil every 250 hours of operation, sample coolant, and change engine oil every 500 hours. Maintenance of electrical and mechanical equipment occurs annually, with diesel engine overhauls after each 20,000 hours of operation. The cycles for standby diesel generators include annual coolant samples, oil samples every 250 hours, oil changes every 1,000 hours, electrical and mechanical maintenance every two years, and engine overhauls every 20,000 hours. The gas turbine cycles include electrical and mechanical maintenance twice annually, over speed protection maintenance and oil and coolant samples annually, and hot section borescope inspections every two years.

11. Critical Spare Parts

Hydro began in 2012 a review of its critical spare parts. It remains in the process of assessing and acquiring critical spares in all asset categories. Following completion, an Asset Criticality Ranking will identify critical spare parts. By the end of 2014, Hydro expects to have completed the reviews of critical spare parts including transformer bushings, power transformers, air blast circuit breakers, and gas turbines.

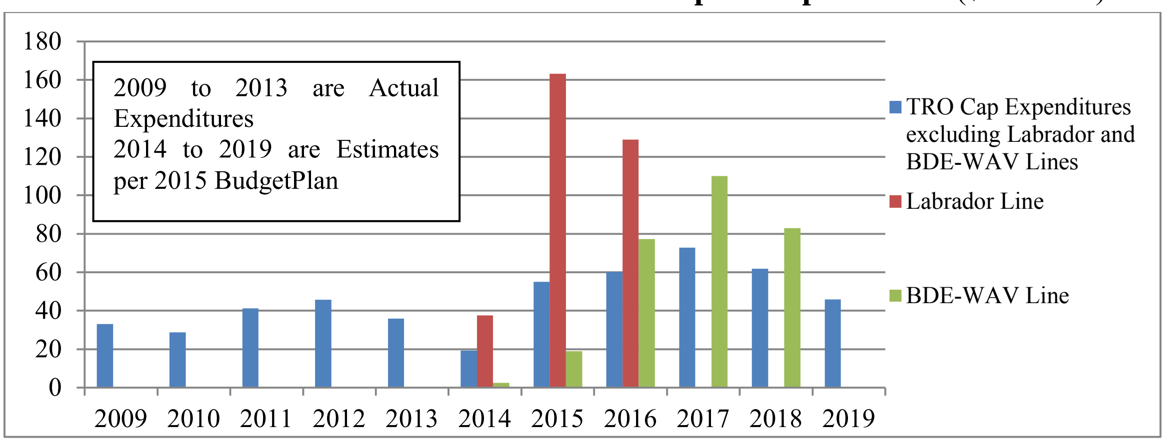
[128] Response to RFI #PUB-NLH-101.
[129] Response to RFI #PUB-NLH-089.
[130] Response to RFI #PUB-NLH-363.
[131] Response to RFI #PUB-NLH-370.

12. Capital Expenditures

Hydro[132] uses an analytical method for prioritizing capital projects. "Level 1" projects comprise must-do work to prevent fatalities, comply with mandatory obligations, and meet load forecasts. The remaining, "Level 2," projects get ranked according to 12 weighted criteria. Weighted scores for each criterion are summed to produce relative rankings, as described in Chapter IV (*Transmission and Distribution Planning and Design*).

Since 2010, Hydro has been making annual capital expenditures[133] of about $8.8 million per year on terminal stations and $4.4 million on transmission line capital projects. For 2015, Hydro proposes to spend $21 million on terminal stations and $186 million on transmission line projects, including about $23 million on the IIS and about $163 million for the West Transmission Line in Labrador. Corresponding annual expenditures for distribution line capital projects have been $14.9 million per year, with $18 million planned for 2015. TRO capital expenditures steadily increased from 2010 to 2012. They then decreased in 2013 and 2014, excluding the new transmission line in Labrador and the new Bay d'Espoir – Western Avalon transmission line. The next chart illustrates that, even after excluding the new transmission lines, TRO capital expenditures are expected to be substantially more for 2015 through 2018 than for years 2009 through 2013.

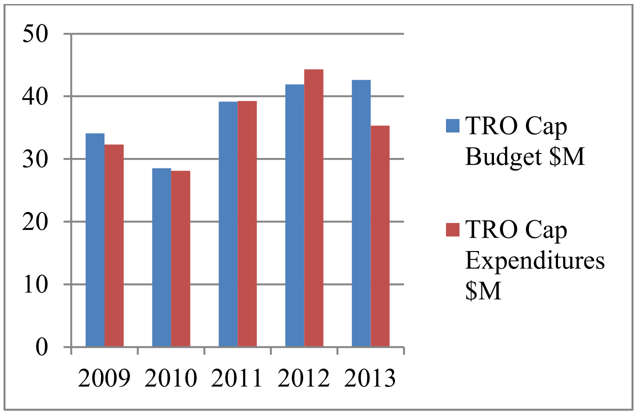
Chart 5.19: Transmission and Distribution Capital Expenditures ($ millions)



The next chart shows a drop[134] in transmission and distribution capital spending (almost $9 million) in 2013 compared to 2012. The 2013 expenditures also ran at about $7 million less than budgeted for that year.

[132] Hydro's 2015 Capital Budget Application; 2015 Project Prioritization, Appendix A.
[133] Hydro's 2015 Capital Budget Application.
[134] Response to RFI #PUB-NLH-156, Attachment 4.

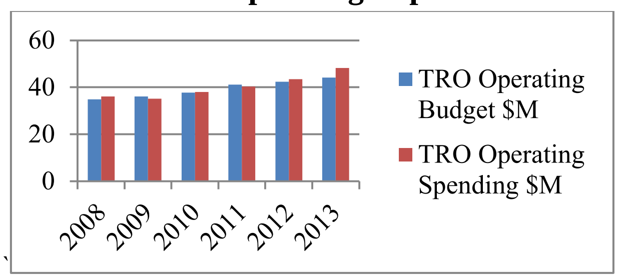
Chart 5.20: Transmission and Distribution Capital Expenditure Variances



13. Operations and Maintenance Expenditures

The next table[135] shows budgeted versus actual operating expenditures in recent years.

Table 5.21: Operating Expenditures



14. Status of 2014 Integrated Action Plans Related to Transmission and Distribution Asset Management

We discuss below the May 2, 2014 Integrated Action Plan items that concern asset management as of December 10, 2014. This plan includes Hydro's responses to the recommendations from Liberty's 2014 Interim Report.

a. *No. 18: Execute a 2014 plan for testing transformers with questionable levels of combustible gases.*

Hydro reports that transformer gas testing has been completed consistent with the plan.

b. *No. 19: Execute a 2014 plan for completing overdue testing and maintenance on critical transformers.*

Hydro's December 10 report indicated that this was completed. The report notes, however, that two of the eight critical transformers have not been completed.

[135] Responses to RFIs #PUB-NLH-155, Attachment 1 and PUB-NLH-156, Attachment 3.

c. *No. 20: Develop a plan for completing overdue testing and maintenance on remaining transformers.*

Hydro completed the plan, and submitted it to the Board on June 2, 2014.

d. *No. 24: Install a replacement for T1 transformer at Sunnyside Terminal Station.*

The unit did not initially pass factory testing requirements. Hydro initiated contingency plans to ensure required transformer capacity by December 1, 2013. The new unit did subsequently pass the factory acceptance tests and has been delivered to Holyrood.

e. *No. 25: Complete refurbishment of T5 transformer at Western Avalon. Due date: 5-Oct-2014*

Hydro reported this work has now been completed.

f. *No. 26: Review the system disruptions in January, 2014, in terms of the performance of facilities, equipment and resources; document unexpected outcomes and lessons learned; implement changes to improve future performance; and communicate these changes to the entire Hydro organization.*

Hydro reports this item as completed.

g. *No. 27: Complete a risk/reward review of the option of installing online continuous gas monitors on all GSU transformers not currently equipped with this equipment.*

Hydro reports development of an overall plan to install monitors on all 22 GSU transformers; 7 in 2015, with the remainder and other 230 kV critical to be upgraded in subsequent years.

h. *No. 29: Complete a formal life assessment of Hydro's power transformers and revise the long term plan for transformer upgrades and replacements as appropriate.*

Hydro reports this as completed.

i. *No. 30: Complete a risk/reward review of the option of requiring additional station service redundancy at all 230 kV terminal stations, and to install back-up service supply in locations recommended by Hydro's Internal Review.*

Hydro reports the assignment of an Asset Specialist to this task, with expected completion by the scheduled date of March 30, 2015.

j. *No. 31: Specify in a Terminals Engineering Standard that the location of the station service transfer switch shall be the control building in stations that have a control building remote to the transformers.*

Hydro reports completion, with the standard added.

k. *No. 32: Review the current location of the station service transfer switches at terminal stations that do not have a control building to ensure their locations are optimal. Due date: Q4 2015*

Hydro will begin this task (scheduled for completion in the fourth quarter of 2015) next year.

l. *No. 33: Execute the annual 2014 plan for exercising air blast (AB) circuit breakers. Due date: 30-Nov-2014*

Hydro reported this work as completed.

m. *No. 34: Execute a 2014 plan for completing overdue testing and maintenance on critical AB circuit breakers.*

Hydro reported this work as completed.

n. *No. 35: Develop a plan for completing overdue testing and maintenance on remaining AB circuit breakers.*

Hydro submitted the plan to the Board on June 2, 2014.

o. *No. 36: Develop a plan for periodically operating AB circuit breakers from protective relays.*

Hydro reported completion of a procedure for inclusion in the Maintenance Manual.

p. *No. 37: Complete an analysis of the DC system for B1L03 to determine the existence of any high impedance paths that may affect its operation.*

Hydro reported completion of a checkout for the DC circuit for breaker B1L03 at Sunnyside.

q. *No. 38: Complete a review of the annual air system leak check PM to ensure adequacy.*

Hydro reported completion of the updated maintenance manual and procedure.

r. *No. 39: Complete a review of the current approach to AB circuit breaker re-lubrication, which addresses why the DOW 55 grease was not removed during the 2007 re-lubrication.*

Hydro reported status as completed. Future lubrications will not be completed outside in the elements. Practices and procedures will be updated following oversight by an air blast circuit breaker expert during an overhaul scheduled for October 2014. A summary report outlined other items, such as lubrications recommended and other maintenance practices.

s. *No. 40: Develop a plan for implementing an accelerated/shortened PM cycle for AB circuit breakers.*

Hydro reported status as completed. The accelerated replacement plan contemplated will only require 21 of the 63 breakers to have a frequency reduction from six to four years.

t. No. 41: Develop a program for the accelerated replacement of AB circuit breakers, with a priority on identifying the activities and areas to be completed during the 2014 maintenance season.

Hydro reported completion and submission to the Board of a consultant report outlining a plan for accelerated replacement of the air blast circuit breakers starting in 2015.

u. No. 42: Review and implement changes to internal procedures related to: a) the application of protective coatings to circuit breakers; b) ensuring that false indications of the open/close state cannot occur in any failure mode; and c) establishing a specific pass/fail criterion related to circuit breaker timing tests.

Hydro reported that the reviews of and changes to internal procedures have been completed.

v. No. 45: Implement process improvements related to the planning, scheduling and execution of work.

Hydro reported status as completed. A committee has established a standardized approach to annual work planning and performance metrics tracking. Resource plans have been developed and resources acquired.

D. Conclusions

5.1. The advanced age of much of Hydro's T&D equipment will require substantial levels of maintenance and replacement.

The comparatively advanced age of Hydro's T&D equipment requires comparatively more intense T&D inspection, maintenance, and system rebuild and modernization programs.

5.2. Hydro conducts vegetation management consistent with good utility practice and the needs of the system.

Vegetation management expenditures have increased from about \$1.3 million in 2009 to about \$2.5 million in 2014.

5.3. Recent improvement in air blast circuit breaker maintenance has produced conformity with good utility practices. *(Recommendation No. 5.1)*

Preventive maintenances between 2010 and 2013 for air blast circuit breakers were problematic. Hydro extended the cycles for such maintenance. That extension did not appropriately reflect the needs imposed by the advanced age of the equipment involved. Neither did it respond well to the observed conditions of the air blast breakers. Hydro substantially escalated maintenance of these breakers in 2014, following the events of January 2014. This escalation brings Hydro's maintenance program for the breakers in line with good utility practices.

5.4. It is not clear that Hydro brings to bear sufficient numbers of skilled resources to prevent undue backlogs in maintenance work. *(Recommendation No. 5.1)*

The emergence of required work beyond planned maintenance activities has led to a pattern of significant, and in some cases growing, backlogs in the planned work. One should expect some backlogging of work to occur. Otherwise, maintaining the efficiency of resources tends to become problematic. The numbers of backlogged work orders should show stability at reasonable levels over time, however. Moreover, when a particularly work-intensive year occurs, temporary backlog increases above reasonably sustainable levels should promptly decrease. Liberty observed a general pattern of year-over-year increases in Hydro's backlogged work orders.

Our review of inspection expenditures indicates that Hydro has intensified inspection activities since 2010. More effective inspections and condition assessments generally produce an increase in resulting maintenance work orders. We observed that 17 percent of Northern Region and 10 percent of Central Region work load has gone to address unplanned activities. Work to address emergent issues reduces the number of resources available for planned work. Besides issues caused by difficulties scheduling planned outages, it appears that Hydro should consider increasing the numbers of its FTE field resources, not including the temporary resources employed for completing projects required by the 2014 Integrated Action Plan. Rather than increasing field resources, TRO reduced its field resources from 84 in 2009 to about 81 in 2013.

5.5. The radial configuration of the distribution and portions of the transmission (particularly 66 kV) systems leads Hydro to defer maintenance work to avoid required customer outages. (*Recommendation No. 5.1*)

Hydro sometimes defers maintenance work on radial facilities, which can require long customer outages for the performance of such work. Hydro undertakes such deferral following an analysis of the risks of failure in the absence of maintenance work performance. We discuss the effects of these outages on reliability metrics in Chapter VI (*System Operations*). Hydro needs a long-term plan for addressing the minimization of reducing customer interruptions during planned maintenance work on radial lines. To the extent that Hydro continues to use this configuration, the facilities involved will continue to age, making it likely that maintenance needs will increase further over time.

5.6. Hydro does not make available to its field personnel the electronic equipment that has come into common use in the industry. (*Recommendation No. 5.2*)

Hydro provides only its relay technologists and transmission inspectors operating under its Wood Pole Line Management program with laptop computers. These personnel use the computers to gather and submit data to Hydro's Computerized Maintenance Management System. Other field personnel use paper forms for work orders and for reporting inspection and work completion findings. Investing in hardware, mobile applications, and electronic connectivity (among field personnel, supervision, and the control center) has generally proven cost effective in our experience.

Hydro has underway a pilot project that employs handheld computers with Geographic Information System ("GIS") capability during inspections of the distribution system and substations. Hydro is also considering implementing an Outage Management System. It intends to use the results from the pilot project to evaluate Outage Management System options.

5.7. Hydro's annual Wood Pole Line Management program reflects best utility practices.

The program seeks to identify and replace transmission poles whose strength has deteriorated sufficiently to require replacement. Hydro appears to employ an appropriate rate of replacement of distribution poles.

5.8. Hydro has been appropriately funding its operations and maintenance work.

Expenditures have conformed reasonably to budgeted amounts. Expenditures in 2013 exceeded the budgeted amount by about $4 million, likely because of unplanned transmission system repairs.

5.9. Hydro has been increasing its transmission and distribution capital investments.

Capital expenditures grew steadily from 2010 to 2012, but decreased in 2013. Capital expenditures then dramatically increased in 2014, driven in major part by the new transmission line in Labrador. Even when new transmission lines are excluded, the TRO capital expenditures are expected to be substantially higher in the next four years, as compared with 2009 through 2013.

5.10. As of the December 10, 2014 report, Hydro reported itself to be on track for completing the transmission and distribution actions listed in the Integrated Action Plan.

We reviewed Hydro's status reports and discussed actions with management in forming this conclusion. We did not verify work through the conduct of substantial field investigation. The action items related to transmission and distribution addressed Asset Management, Transmission and Rural Operations, Project Execution and Technical Services, and Long Term Asset Planning.

E. Recommendations

5.1. Formulate a comprehensive and structured plan to bring maintenance backlogs to a more appropriate sustained level. *(Conclusions Nos. 5.3, 5.4 and 5.5)*

Hydro needs to examine the root causes of maintenance work deferred more than one year. Hydro needs to determine how to better manage emergent work without causing undue impact to planned maintenance work. Hydro also needs to improve its ability to maintain radial lines without causing lengthy customer interruptions. Proper analyses may identify the need to increase field resources and the need to install more switching and mobile generation to minimize the effect of planned maintenance outages, as discussed earlier in this report.

Hydro should complete the plan, adjust resources as required, and provide a report to the Board on the plan and actions taken by December 15, 2015.

5.2. Perform a cost/benefit analysis of providing crews with laptop computers. (*Conclusion No. 5.6*)

Hydro should promptly and formally study the benefits of expanding the availability of electronic functionality and connectivity for field resources. The study should consider how best to equip transmission, distribution, and terminal station inspection and maintenance personnel to receive and submit work orders, check lists, and completion data.

Hydro should complete the analysis and provide it to the Board by June 30, 2015.

VI. System Operations

A. Background

Electric utilities operate electric systems differently. Some monitor and control both transmission system and distribution systems from one central control center. Others, like Hydro, employ a transmission system control center, while dividing distribution control among regional operating centers. These multiple centers operate the distribution system within their assigned regions.

Operators assure transmission system operation within the limits of operating criteria. This role requires that they have the means to monitor transmission system load flows, bus voltages, and the status of circuit breakers. They need real-time awareness of equipment alarms and changes in system status (*e.g.*, the tripping of circuit breakers or abnormal load flows). Safety of employees performing transmission line and substation (terminal station) work requires that system operators have authority over switching and tagging procedures. System operators assist regional operating offices by monitoring abnormal conditions (*e.g.*, the lock out of a distribution feeder breaker or recloser) and by communicating those conditions to regional operating centers.

Liberty examined for this report how Hydro's Energy Control Center operates the transmission system, and assists regional operating centers in operating their distribution systems. We also examined the use of computer-assisted aids, such as SCADA and Energy Management System to monitor the transmission system and to predict abnormal loading conditions before they occur. Liberty also examined the extent to which SCADA monitoring and control applies across Hydro's distribution systems.

Liberty addresses system operation during outages in Chapter VII (*Outage Management*) and how it manages system emergencies in Chapter VIII (*Emergency Management*).

B. Chapter Summary

Hydro operates the transmission system from the Energy Control Center located at Nalcor's headquarters in St. Johns. The Center has controlling authority for Hydro's generation facilities and nearly all of Hydro's transmission (46 kV and higher) system. Operations of Hydro's Island Interconnected System distribution systems occurs at two Transmission and Rural Operations ("TRO") Regional Service Centers on the Island. Their locations are at Bishop's Falls (for the Central Region) and at Port Saunders (for the Northern Region). Management of these two regions has controlling authority for distribution operations in their territories. Hydro also operates a regional service center in Labrador. Some transmission resources on the Great Northern Peninsula operate under the switching control authority of the local manager. The System Operators at the Energy Control Center assist the local manager by executing SCADA-controlled switching operations, where applicable.

Liberty found operation of the Energy Control Center to be consistent with good utility practices. Appropriate transmission system operator and support engineer staffing use effective and industry-representative, computer-based tools. These tools include SCADA monitoring and control and Energy Management System energy and demand management. System Operators monitor and control Hydro's generation and transmission system via control consoles displaying system configuration diagrams provided by the SCADA/Energy Management System. The diagrams indicate the dynamic (real-time) status of loads, bus voltages, frequencies, circuit breakers, and other equipment. They display alarms when operating issues occur. Hydro still employs a large, fixed static board displaying the transmission system in total. Many utilities have removed static boards, because operator consoles already display the relevant data and because of the costs to upgrade the static display and associated wiring following transmission system modification. The Muskrat Falls link to the Interconnected Island System illustrates an example of a major change of this type.

Liberty's review of system operations disclosed a concern about the lack of SCADA monitoring and control of all of Hydro's distribution feeders. Good utility practices generally include much broader feeder monitoring under SCADA than Hydro has at present. By contrast, Hydro only has some level of remote control and monitoring for ten of its thirty-four Island Interconnected System distribution feeders. The remaining 24 have no remote control or monitoring. The operating regions would gain effectiveness in identifying feeder outage locations, monitoring feeder loads, and controlling their distribution systems through access to their feeder reclosers. This access could come directly, or indirectly via the Energy Control Center, through broader SCADA installation.

C. Findings

1. The Energy Control Center

Hydro operates its Energy Control Center from its St. John's headquarters. Hydro maintains a back-up Control Center at an off-site location. The Energy Control Center controls all Hydro generation and transmission resources on the IIS and on the Labrador system. The Center holds switching permit and tagging control authority for the transmission system. Local management has switching control authority for distribution systems and for a few transmission resources on the Great Northern Peninsula. System Operators at the Energy Control Center assist local management by executing needed switch operations via SCADA.

The Energy Control Center sits adjacent to Nalcor's Corporate Emergency Operations Center. Chapter VII (*Emergency Management*) addresses the emergency center.[136] The Energy Control Center has five Systems Operations Engineer positions and eleven operator positions, including supervisors.

System Operators can monitor the transmission system via the SCADA and Energy Management systems on their control consoles. They can also do so from a large static board that shows the entire transmission system. The data encompasses transmission circuits, terminal stations, and generating stations. The System Operators can view load flows on the transmission circuits and interconnection points, system voltages and frequencies, circuit breaker positions, and any alarm conditions identified by the SCADA system. System operators place value on the static board,

[136] Nalcor's Emergency Operations Plan.

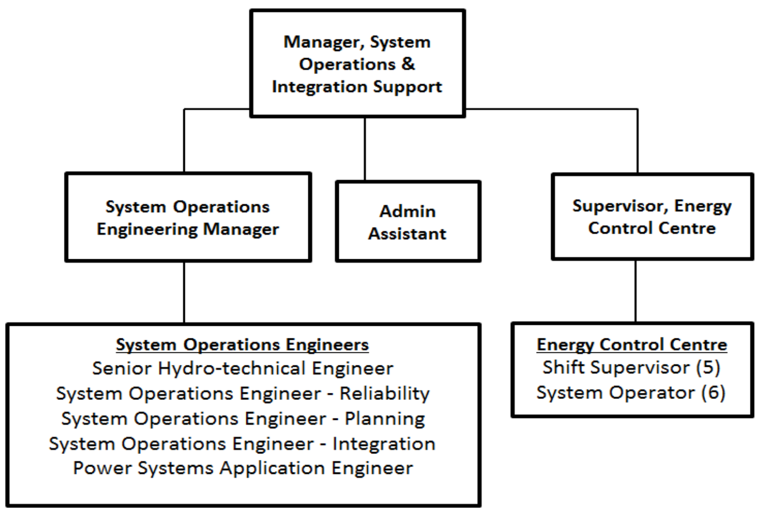
even though their consoles provide the same information. The static board has the advantage of depicting the entire system.

The Energy Control Center conducts two or three training exercises per year to provide outage/storm training. These exercises employ simulator station and mock interaction with field forces, under the guidance of the instructor.[137]

2. Energy Control Center Staffing

The System Operations Department staff of 20 has direct responsibility for the operation of Hydro's interconnected generation and transmission systems on the Island of Newfoundland and in Labrador. The Manager, System Operations and Integration Support, heads the two groups that comprise the department: the Energy Control Center and the System Operations Engineering Group.[138] This staff provides directly for the operation of the system and for engineering support. The next chart displays the organization and staffing.

Chart 6.1: Energy Control Center Organization



3. Transmission Systems Operations

The Supervisor, Energy Control Center, has overall responsibility for the Energy Control Center.[139] Staffing for each shift includes a Shift Supervisor and a System Operator, who operate the power system. A total complement of 11 shift personnel (five Shift Supervisors and six System Operators) provides 24/7 coverage, and staffing is sufficient to allow time for training, support and leaves. The Center's staff uses an Energy Management System to monitor and control the transmission system in accordance with reliability and design criteria.

System Operator candidates must complete a three-year electrical technology program from a recognized technical institute, hold certification as a hydroelectric plant journeyman operator,

[137] Response to RFI #PUB-NLH-195.
[138] Response to RFI #PUB-NLH-181.
[139] Response to RFI #PUB-NLH-181.

and have experience as a hydroelectric plant operator. New operators undergo six months of formal training before placement in a shift rotation. System Operators with at least five years of experience can become candidates for Shift Supervisor positions.

4. Transmission System Operations Engineering

The System Operations Engineering Manager's team of five Engineers provides guidance and technical support to Energy Control Center management and operation. The team consists of a:

- Senior Hydro-technical Engineer
- System Operations Engineer – Reliability
- System Operations Engineer – Planning
- System Operations Engineer – Integration
- Power Systems Application Engineer.

The System Operations Engineering Group provides guidance and technical support to the Operators, including the integration of new assets into the system. Responsibilities of this group include:

- Generation outage planning for the coming two years, including working with Newfoundland Power and other generation suppliers to coordinate
- Producing daily reports for the Board and conducting billing, metering and invoicing of Hydro's major customers
- Conducting analyses of system stability for planned and emergency transmission outages, including optimum power flows and contingency analyses
- Monitoring system and facility reliability and recommending improvements
- Tracking generator status, forced outage rates, and bulk electric data at Hydro/Newfoundland Power interconnection points
- Supporting Energy Control Center computer applications.

A new "Integration" engineer position has responsibility for managing integration of the Muskrat Falls Project, the Labrador Island HVDC Link, the HVDC Maritime Link to Nova Scotia, and other projects associated with them.

5. Energy Control Center Tools

System Operators use computer-based tools in controlling the transmission system. These tools include an Energy Management System, Supervisory Control and Data Acquisition System ("SCADA"), and Nostradamus, a load forecasting tool that forecasts short-term (next day to seven days) energy and peak demands. Chapter II (*Planning and Supply*) addresses issues with the performance of Nostradamus in extreme weather circumstances. This chapter, Chapter VI (*System Operations*) addresses Hydro's operation of its electric systems in normal conditions. The Energy Control Center interfaces with a Customer Contact System to address customer outage needs. The Power Outage Emergency System ("POES") provides for communication of Estimated Restoration Times ("ERT") internally and to customers. Chapter VII (*Outage Management*) addresses restoration time reporting. Hydro does not employ a computer-based

Outage Management System ("OMS"), which distinguishes it from many other utilities. We discuss the lack of such a system in Chapter VII (*Outage Management*). [140]

6. Transmission System SCADA

Hydro's SCADA system provides wide flexibility in alarming and data capture querying. Its ability to monitor hundreds of thousands of data points permits efficient expansion. System Operators use the Energy Control Center's SCADA system to monitor and control thirty-seven of the fifty-two transmission terminal stations.[141] SCADA monitoring, but not control, exists at an additional terminal station; *i.e.*, the Frequency Converter at the Corner Brook Pulp & Paper Mill in western Newfoundland. Fourteen terminal stations have neither monitoring nor remote control. These terminal stations serve only Hydro's distribution system, which makes them essentially distribution substations.

Fifty-three of Hydro's fifty-six transmission circuits operate under SCADA control and monitoring. The three transmission lines not under SCADA control are radial 66 kV circuits. Hydro indirectly monitors one of these 66 kV circuits. This monitoring uses Hydro's Automated Meter Reading function for customers served off the feeders fed by this transmission line. Hydro can monitor the other two 66 kV circuits (considered taps of a radial line) via the radial mainline.

7. Energy Management System

The operation of the Energy Management System helps the Energy Control Center to assess operating conditions on the transmission system.[142] The Energy Management System software contains a digital model of Hydro's generation and transmission systems. It continually monitors system loads, voltages, and frequency. Hydro also uses the Energy Management System to predict system conditions when planning removal of transmission system elements from the system to conduct maintenance work. Hydro installed its current Energy Management System in 2006 and last updated it in 2013. Hydro's Information Services Department, which has eight personnel, supports and maintains the Energy Management System.

8. Nostradamus

The Energy Control Center uses a *Nostradamus* application (provided by Ventyx, a subsidiary of ABB Corporation) to develop short-term transmission system demand forecasts.[143] Nostradamus uses SCADA/Energy Management System data to predict loads across a one to seven day horizon, providing hourly time steps. Hydro creates three forecasts: one for the Avalon Peninsula, one for the Hydro System, and one for the Island Interconnected system. The Nostradamus neural network algorithm learns (from processing historical data) the pattern of load changes by considering variables that include weather, day of week, and time of day. System Operations uses Nostradamus forecasts to assist in determining generation reserves and unit commitment and scheduling, and to conduct equipment outage assessments.

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140 Response to RFI #PUB-NLH-407 and 408.
141 Response to RFI #PUB-NLH-102, 103, 405, and 406.
142 Response to RFI #PUB-NLH-408.
143 Response to RFI #PUB-NLH-409.

Nostradamus has proven useful for predicting normal peak demands on Hydro's system, but System Operators have found it unreliable in times of extremely low ambient temperatures. Chapter II (*Planning and Supply*) discusses the inability of Nostradamus short-term forecasts to function well during certain weather events. Hydro has been working with the software vendor to improve forecast performance.[144]

9. Coordination with Newfoundland Power

Technically and by tariff, Newfoundland Power is a Hydro "customer." However, this term does not accurately capture the robustness of the relationship. Newfoundland Power provides electricity to over 256,000 end-use customers of its own, and consumes about 85 percent of Hydro's generation in doing so. The nature of their relationship requires a scope and depth of coordination that goes well beyond the needs that even the largest retail customers entail.[145]

Communications and coordination between Hydro and Newfoundland Power occur at multiple levels. At the operating level, their SCADA systems exchange some real-time monitoring data, using the Inter-Control Center Communications Protocol ("ICCP") communications link. On a regular basis, inter-utility committees or working groups meet at working and executive levels. The real-time data shared via the SCADA ICCP link includes:

- Individual generating unit output and status
- Newfoundland Power demand, but not the real-time total Island Interconnected System demand for both utilities; however, Hydro's Energy Control Center expects to provide total demand to Newfoundland Power starting with the 2014/2015 winter season
- System frequency.

Information exchanged annually includes:

- Newfoundland Power provides Hydro with its five-year forecast of monthly energy and demand requirements of Hydro
- The two discuss and coordinate the performance of Newfoundland Power's generation plants for the winter season.

Monthly information exchanges include Hydro's issuance to its System Operators of a report of the costs and start-up times of stand-by generators, including Newfoundland Power's diesels and combustion turbines. On a daily basis, the system operators of the two communicate with each other to coordinate generation resources to meet system demands. These communications focus on the availability of Newfoundland Power's hydro units. They remain off-line during off-peak hours to allow a retention of water for peak time generation. During emergency situations, additional coordination and communications occur. Chapter VIII (*Emergency Management*) discusses this subject.

Hydro could not provide any single document outlining the processes of coordination between the two utilities.[146] Hydro, however, does maintain a list of individual procedures that affect

[144] Interview System Operations Manager 9-Oct-2014 and Response to RFI #PUB-NLH-411.
[145] Response to RFI ##PUB-NLH-007.
[146] Response to RFI #PUB-NLH-054.

Newfoundland Power that come into play for normal or emergency conditions, identified as follows:

- 010 – System Outages
- 042 – Forest Fires near transmission lines
- A-003 – Notification of weather warnings and lightning activity
- T-001 – Generation Load sequencing and Generation shortfalls
- T-007 – Holyrood Black Start Using Hardwoods Gas Turbine
- T-032 – Restoration Plans for loss of TL202 and TL206
- T-078 - Hardwoods and Oxen Pond Restoration

10. Distribution System Operations

Separate Central and Northern Regional Service Centers, operating as part of the Transmission and Rural Operations (TRO) organization, manage the operation of their distribution systems.[147] The Energy Control Center keeps the Regional Field Supervisors and Front Line Supervisors informed about transmission system operations and about any SCADA-controlled equipment operations affecting the distribution systems. The Energy Control Center also assists the Regions by operating SCADA-controlled circuit breakers under the control authority of the Regional Front Line Supervisors. The Distribution Front Line Supervisor directs work on the distribution system, and acts as the controlling authority for work protection. The Short Term Planning and Scheduling group plans outages. The Support Services group communicates outage plans to customers. The Asset Specialists and Equipment Engineers of the Long Term Asset Planning group monitor performance of the distribution system.

Only ten of Hydro's thirty-four distribution feeders on the IIS have some level of remote control and monitoring. The remaining twenty-four have neither remote control nor monitoring.

D. Conclusions

6.1. Hydro's Energy Control Center has an adequate number of experienced operators and trainees, as well as well-defined roles for support engineers.

The Energy Control Center has sufficient staff. Its personnel include appropriately trained System Operators. Hydro provides appropriate engineering support to the Energy Control Center.

6.2. Hydro's Energy Control Center is appropriately equipped with computer-based tools for operating its transmission system, including SCADA monitoring and control, Energy Management System energy and demand management.

System Operators monitor and control Hydro's generation and transmission system via control consoles that display SCADA/Energy Management System provided system configuration diagrams indicating the dynamic (real-time) status of loads, bus voltages, frequencies, circuit breakers, and other equipment, and that display alarms when operating issues occur.

[147] Response to RFI #PUB-NLH-182.

Hydro's modular SCADA/Energy Management System application permits expansion to increase the numbers of data points and to add adding applications (*e.g.*, as an outage management system). Hydro experienced an issue with the accuracy of Nostradamus application in forecasting short-term loads during periods of very cold weather (as occurred in January 2014). Hydro has been working with the software vendor to mitigate the issue, as Chapter II (*Planning and Supply*) discusses.

6.3. Hydro shares real-time data, via a link between SCADA systems, with Newfoundland Power.

The data does not yet include total Island Integrated System demand, but doing so is planned for the near term. Hydro and Newfoundland Power have been verbally sharing generation availability on a daily basis and other information on monthly and annual bases.

6.4. Hydro has not installed SCADA monitoring and control on a sufficient number of its distribution feeders. *(See Recommendation No.3.6 in Chapter III)*

Hydro has not provided SCADA monitoring and control of all distribution feeders. Only ten of Hydro's thirty-four distribution feeders on the Island Interconnected System have some level of remote control and monitoring. The operating regions would be more effective in identifying feeder outage locations, monitoring feeder loads, and controlling their distribution systems if they had access to their feeder reclosers (and various substation alarms). Installing SCADA on more feeders would provide this capability. Expanding SCADA monitoring and control of the distribution system will improve key reliability metrics (*e.g.*, SAIDI customer minutes of interruption).

The lack of SCADA on the distribution system has not resulted from hardware or software limitations. Current wireless broadband and other communications technology have improved the economics of extending monitoring to substations and terminal stations serving distribution feeders.

E. Recommendations

Liberty has no recommendations concerning system operations, but notes the related Recommendation No. 4.6.

VII. Outage Management

A. Background

Liberty addressed system operations as part of the work for this report. Chapter VI (*System Operations*) discusses overall operations of Hydro's system. This chapter discusses response to outages on the transmission and distribution systems, outage management practices, outage cause coding, and communications with Newfoundland Power regarding planned transmission system equipment outages.

Use of an Outage Management System comprises best utility practice for distribution systems, providing the capability to:

- Predict the location of a fuse or a recloser that opened when feeder faults occurred - using outage reports and known electrical distribution system connectivity
- Prioritize restoration efforts and manage resources based upon criteria such as locations of emergency facilities, size of outages, and duration of outages
- Provide media and regulators information on the extent of outages, the numbers of customers impacted, and estimated restoration times.

Outage Management Systems comprise software applications that can process outage reports from a variety of utility operational systems including SCADA, Automated Metering Infrastructure, and customer phone contacts. Such applications enable the display of outage information to utility operators. An effective Outage Management System can help a utility interpret outage information, and determine likely cause(s). It can also help optimize the application of service restoration resources.

Ultimately, an Outage Management System serves to reduce both SAIDI and customer minutes of interruption by reducing restoration times. An effective system also reduces operating costs by increasing the effectiveness and efficiency of restoration crews.

B. Chapter Summary

The Energy Control Center manages transmission system outages. Transmission and Rural Operations ("TRO") Regional Field Supervisors manage distribution system outages. The two responsible authorities employ similar outage management practices. The major difference lies in the degree of SCADA coverage. Hydro has not installed SCADA on much of its distribution system. Hydro sufficiently uses SCADA to cover its transmission system. Chapter III addresses gaps in SCADA coverage of the distribution system.

Energy Control Center practices for identifying forced transmission outages and dispatching regional transmission personnel conform to good utility practices. The Center's SCADA system alerts System Operators when circuit breakers trip. System Operators alert the Regional Transmission and Rural Operations Center, which dispatches transmission linemen to address the transmission system issue. Tracking and reporting of transmission-caused customer outages follows a pattern similar to what occurs for distribution outages (which we discuss below).

When a distribution system customer outage occurs, however, the Energy Control Center generally does not know until customers start making contact. Knowledge is, however, immediate for distribution feeders operating under SCADA. Customers make contact during normal business hours through the Customer Care Center. They do so directly through the Energy Control Center after hours.

When the Energy Control Center learns of the outage, it alerts Regional personnel responsible for distribution outage management. Regional personnel must then identify manually the feeder on which customers have the outage. After locating the feeder, local management can dispatch distribution lineworkers to restore service. Responding lineworkers must call the Customer Care or the Energy Control Centers at least hourly to provide updates on estimated restoration times. Hydro's Power Outage Emergency System ("POES") records and tracks customer outages. This system enables customers to call through Hydro's Interactive Voice Recognition ("IVR") system to obtain outage information. Hydro's website provides a second option for securing outage information. Hydro's line crews responding to distribution outages complete paper Distribution Trouble Report forms. These forms provide a comprehensive summary of each outage event, including causes and restoration times. Hydro manually calculates customer outage statistics from the forms.

Liberty found Hydro's processes for managing distribution system outages functional. Nevertheless, they represent legacy methods that do not conform to current best utility practices. Employing modern, computer-based SCADA\Outage Management System\AMI technologies, along with laptop computers for responders can serve immediately to identify outage locations and the nearest protective device. Current practice integrates these technologies with applications for communicating estimated restoration times, for electronically recording outage data, and for identifying the numbers and locations of affected customers.

The advantages of implementing these modern technologies include quicker dispatch of restoration crews to fault locations, elimination of crew paperwork, ending reliance on phone communications, providing electronic notice of estimated restoration times to the Power Outage Emergency System, producing automatic verification that service is restored, and automatically recording and analyzing outage data. In addition to reducing labor costs, employing these technologies will improve customer service by reducing customer minutes of interruption and reducing Hydro's SAIDI.

Liberty found Hydro's field resources for responding to customer outages sufficient. Hydro's lack of an Outage Management System requires it to use paper forms for recording outage work and outage causes. It analyzes outage causes and estimated restoration times manually. Hydro's use and analyses of outage cause codes, however, conforms to good utility practices.

C. Findings

1. IIS Outage Management

Hydro does not have an automated Outage Management System. Hydro cites its small number of retail customers on the IIS and their locations in predominantly rural and widely dispersed areas as barriers to instituting such a system. In particular, Hydro does not consider the benefits as justifying the costs under these circumstances. The current outage management process operates on a fully manual basis. Hydro's current Energy Management System however has the ability to accept an integrated Outage Management System module. The open source system Hydro uses permits the addition of integrated modules at relatively low cost.

Hydro is currently looking at means to enhance its "customer experience" in a number of areas, through a five-year customer service strategic plan.[148] Its short term focus concentrates on enhancing targeted and existing tools and processes to serve Hydro customers better. Hydro has not yet examined an automated Outage Management System. An assessment of this technology, however, will form part of examining Hydro's Customer Service Strategy. Hydro anticipates discussions of synergies and potential integration opportunities for integration of its customer service activities with those of Newfoundland Power.

As Hydro continues with its Automated Meter Reading program, it will have the enhanced capability to detect when a meter is not energized. This capability will help identify individual customers without power, allowing Hydro to identify and respond to specific locations.

In the interim, Hydro will continue to manage outages with its legacy manual processes.

2. Methods for Identifying and Responding to Outages

System Operators can immediately identify forced outages on Hydro's[149] SCADA-monitored transmission circuits, terminal stations, substations, and distribution feeders. SCADA/EMS alarms in the Energy Control Center provide this capability. System Operators notify the appropriate regional supervisor to dispatch the appropriate crews.

The majority of Hydro's distribution main line and lateral feeders, however, do not possess SCADA capability. Hydro can only identify outages on non-SCADA feeders when[150] customers report outages via Hydro's toll-free telephone number. Outage calls go to the Customer Contact Center during normal business hours and to the Energy Control Center during off-hours. Hydro uses a website to provide outage updates. Customers cannot, however, report outages to Hydro online.

For outages reported to the Customer Care Center, the representative provides the needed information electronically or by phone to the appropriate Regional Field Supervisor. This Supervisor then calls a Front Line Supervisor, who then dispatches crews.[151] For after-hours reporting to the Energy Control Center, the System Operator contacts the on-call supervisor, who then dispatches a crew. The crews then must locate the outage, identify causes, and restore service.

[148] Response to RFI #PUB-NLH-404.
[149] Response to RFI #PUB-NLH-195.
[150] Response to RFI #PUB-NLH-196.
[151] Response to RFI #PUB-NLH-196.

3. Customer Outage Communications

Hydro's custom-built communications program, Power Outage Emergency System, supports outage communications. This Bell-Aliant application[152] enables customers to call into Hydro's Interactive Voice Recognition system, or to obtain outage information from Hydro's website. Internal communications use an e-mail system that has a prescribed distribution list. The Customer Care or Energy Control Centers provides updates. The distribution list includes Corporate Communications, Customer Service, System Operations and the Energy Control Center. Energy Control Center and Customer Call Center personnel receive Power Outage Emergency System training upon entry into their positions. Training modules accompany modifications to the system. The Power Outage Emergency System has not changed significantly since 2010.

When a power outage occurs, the Customer Care or the Energy Control Centers enter the following information into the Power Outage Emergency System for all transmission outages and for all after-hours distribution outages:

- Time the power or equipment went out
- Outage cause
- Current Estimated Restoration Time
- Communities affected
- Number of customers affected
- Whether crews are on-site; if not, their estimated time of arrival.

Crews report restoration status on an at least an hourly basis to either the Customer Care or Energy Control Centers, which update the Power Outage Emergency System.

If one of Hydro's five major industrial customers is affected by an outage, the Energy Control Center speaks directly by phone with any of Hydro's five major industrial customers that may suffer outages, and provides updates. These five customers have direct lines into the Energy Control Center.

4. Recording Outage Causes

Line crews responding to distribution outages complete a TRO Distribution Trouble Report. This paper form provides a comprehensive summary of each outage event.[153] Information collected on this form includes:

- Location of the fault (feeder, region)
- Device(s) and components affected
- Number of customers affected
- Interruption start and restoration times
- Outage Cause Codes
- Actions taken to restore service.

[152] Response to RFI #PUB-NLH-196.
[153] Response to RFI #PUB-NLH-185.

Hydro uses outage cause codes to identify transmission and distribution outage causes. For transmission outages, Hydro follows the CEA's outage cause codes for reporting outages on the transmission system when coding equipment outages.[154]

Distribution system outages require Hydro's line crews to submit a paper "TRO Distribution Trouble Report" for each trouble call. Office clerks enter the reported data into the Distribution Outage Reporting System database.[155] An Asset Specialist – Distribution reviews and verifies report information. The Asset Specialist monitors the trouble reports for each distribution feeder, in order to identify any trends or commonalities in substandard materials or in work practices that may warrant improvement.

Going beyond CEA's coding, Hydro further refines its cause codes to help identify Hydro-specific issues of concern. The next table lists Hydro's outage cause codes. The bolded entries indicate Hydro-specific refinements.

Table 7.1: Distribution Outage Cause Codes

Unknown/Other	Adverse Environment
Scheduled Outage/Planned	**Adverse Environment – Corrosion**
Loss of Supply	**Adverse Environment – Salt Spray**
Tree Contacts	Human Element/Error
Lightning	Foreign Interference
Defective Equipment	Foreign Interference – Blasting
Defective Equipment – Flashover	Foreign Interference – Object
Defective Equipment – Overload	Foreign Interference – Vehicle
Adverse Weather	Customer Request
Weather – Galloping Conductor	

The lack of an Outage Management System requires Hydro to manually calculate the number of customers affected by each feeder outage.[156] The Customer Services Department maintains a database. It includes the distribution system and feeder number assignment for each distribution customer. Hydro generates a monthly report to this database. This report lists active customers by distribution system and feeder. Field personnel use this information to determine the number of customers affected by outages, whether across the entire distribution system or by particular feeder(s). An outage does not necessarily affect all customers on a feeder. Field personnel must use distribution system layout drawings listing each customer connected to the feeder when addressing such outages. The field personnel must manually count the number of affected customers. An Outage Management System programmed with distribution system electrical connectively data would perform this function electronically.

When transmission outages occur, Energy Control Center Operators enter cause codes into the Reliability Reporting System database. A Senior System Operations Engineer – Reliability[157] trains Energy Control Center operators in use of the cause codes, in reviewing the cause entries,

[154] Response to RFI #PUB-NLH-185.
[155] Response to RFI #PUB-NLH-185 and 401.
[156] Response to RFI #PUB-NLH-402.
[157] Response to RFI #PUB-NLH-185.

in conducting initial investigations into the causes of the outage, and in updating entered cause codes where required. Unknown outage causes receive an entry of "undetermined" as the cause code. The Senior System Operations Engineer updates this entry following event investigation. Such investigations include discussions with field staff as necessary. The Operations Engineer participates in CEA workshops that address the proper use of codes. The Association has also published manuals that provide a reference for reporting purposes. Hydro's transmission system cause codes include general code groups for Defective Equipment, Adverse Weather, Adverse Environment, System Conditions, Human Element, Foreign Interference, and Loss of Generation. Each code group contains more specific codes that refine cause descriptions.

5. Outage Response

The two regional Transmission and Rural Operations service centers for the Island Interconnected System are located at Bishops' Falls (for the Central Region) and at Port Saunders (for the Northern Region). These centers dispatch distribution or transmission line crews to respond to outages.[158] The next two tables list the numbers and types of distribution and transmission responders available. Personnel classified as Ground Persons and Utility Workers for Northern Region Distribution are available for only May through December. Distribution and terminal station skilled workers can assist transmission line workers in responding to transmission outages.

Table 7.2: Distribution Outage Responders

Classification	Central	Northern
Line Worker - Distribution	26	20
Driver Grounds Person	0	4
Utility Worker	0	2
Total	**26**	**26**

Table 7.3: Transmission Outage Responders

Classification	Central	Northern
Line Worker - Transmission	19	3
Driver Grounds Person	1	1
Utility Worker	0	1
Total	**20**	**5**

6. Intercompany Outage Communications

The SCADAs of Hydro's Energy Control Center and Newfoundland Power's System Control Center are linked together via the Inter Control Center Protocol data link. The linked systems communicate critical loading and equipment status data about each other's transmission systems.[159] The two control Centers contact each other if the SCADA systems indicate the occurrence of a forced equipment outage. The SCADA link allows both utilities to monitor planned and forced outages on each other's transmission systems.

Hydro's Center informs Newfoundland Power's Center when Hydro's transmission and terminal

[158] Response to RFI #PUB-NLH-183 and 400.
[159] Response to RFI #PUB-NLH-410.

station equipment experiences a forced outage, and communicates potential impacts to Newfoundland Power. Hydro keeps Newfoundland Power updated on the status of each transmission outage, estimating when Hydro expects the equipment involved to return to service.

Hydro periodically must remove equipment from service to conduct planned transmission maintenance and construction work. Hydro's System Operations first discusses with Newfoundland Power planned outages that may affect the latter, before Hydro authorizes planned transmission equipment outages. The two entities review:

- Potential reliability issues to both systems
- Whether load flow studies should take place
- Loading constraints (*e.g.*, transmission line and transformer limitations, given the short term load forecast)
- Outage start time and duration
- Contingency plans.

Hydro's System Operations notifies Newfoundland Power's System Operations on the day of the planned transmission equipment outage, and provides outage status updates throughout the day.

D. Conclusions

7.1. The manual, paper-based outage management process does not conform with best utility practices. *(Recommendation No. 7.1)*

Hydro believes that its small end-use customer base (spread across its service territory on the IIS) does not justify the expense of adopting a computer-based Outage Management System, given the cost. Liberty believes that an Outage Management System would improve customer service, SAIDI metrics, communication with outage responders (if provided with laptop computers), and estimated restoration time accuracy. It would also reduce unnecessary responder phone communications and travel times, and eliminate outage reporting paper burdens and manual calculation of outage statistics.

7.2. The ability to detect customer outages following installation of automated meter reading should work with an Outage Management System.

As Hydro continues with its Automated Meter Reading program, it will have the enhanced capability to detect when a meter is not energized. This will help identify individual customers without power, and allow Hydro to respond more quickly to specific locations.

7.3. Hydro has adequate protocols for communication with Newfoundland Power regarding planned transmission, generation, and terminal station equipment outages.

E. Recommendations

7.1. Study the costs and benefits of a variety of Outage Management System opportunities in order to provide a basis for assessing potential options. *(Conclusion No. 7.1)*

Hydro needs to consider (following careful study) what types of Outage Management System capabilities may improve the effectiveness and efficiency of outage response and reduce customer outage durations. Such a system may make sense as an addition to its existing

SCADA/EMS packages, or as a separate software program, such as employed by Newfoundland Power. Hydro should report to the Board the results of its study and its recommendations by September 1, 2015.

VIII. Emergency Management

A. Background

Liberty addressed emergency management as part of the work reviewed in connection with this report. Utilities experience a variety of "emergencies." Liberty's focus in this phase of the investigation was Hydro's preparation for and conduct during and after severe weather events, and generation and transmission system shortfalls. Typically, a utility has general emergency plans, but uses separate Storm Preparation and Outage Restoration Manuals. These manuals address tracking severe storms. They also anticipate weather that is sufficiently severe to cause damage to equipment and to cause substantial customer interruptions of lengthy duration by addressing preparation and actions before, during, and after damage and interruptions have occurred. Liberty examined Hydro's Emergency Management practices and its Severe Weather Preparedness and Restoration practices. Liberty also reviewed how Hydro applied these practices during the January 2014 events and whether it has applied lessons-learned from past events.

B. Chapter Summary

The Nalcor/Hydro Corporate Emergency Operations Center, its organizational structure, and Nalcor's Corporate Emergency Response Plan ("CERP") protocols conform to good utility practices in addressing all types of emergencies. One gap that exists, however, is insufficient treatment of catastrophic shortfalls in generation and transmission, and customer interruption duration. The Plan indicates that Hydro managers can call for minor, major, or catastrophic levels of emergencies, but the plan does not sufficiently inform managers about what minor, major, and catastrophic power outage emergencies entail.

Hydro's Severe Weather Preparedness Protocol, which has recent enhancements resulting from lessons-learned, conforms to good utility practices in preparing for pending severe weather events, including for prolonged cold weather which could contribute to equipment issues. One exception is that Hydro has not defined minor, major, or catastrophic power outages here either.

Other than a few documents for restoring specific generators or transmission lines, Hydro does not have a system restoration protocol or manual for providing guidelines for critical items, steps, and priorities for restoring transmission and distribution customers. Good utility practices call for the use of such a restoration guide.

C. Findings

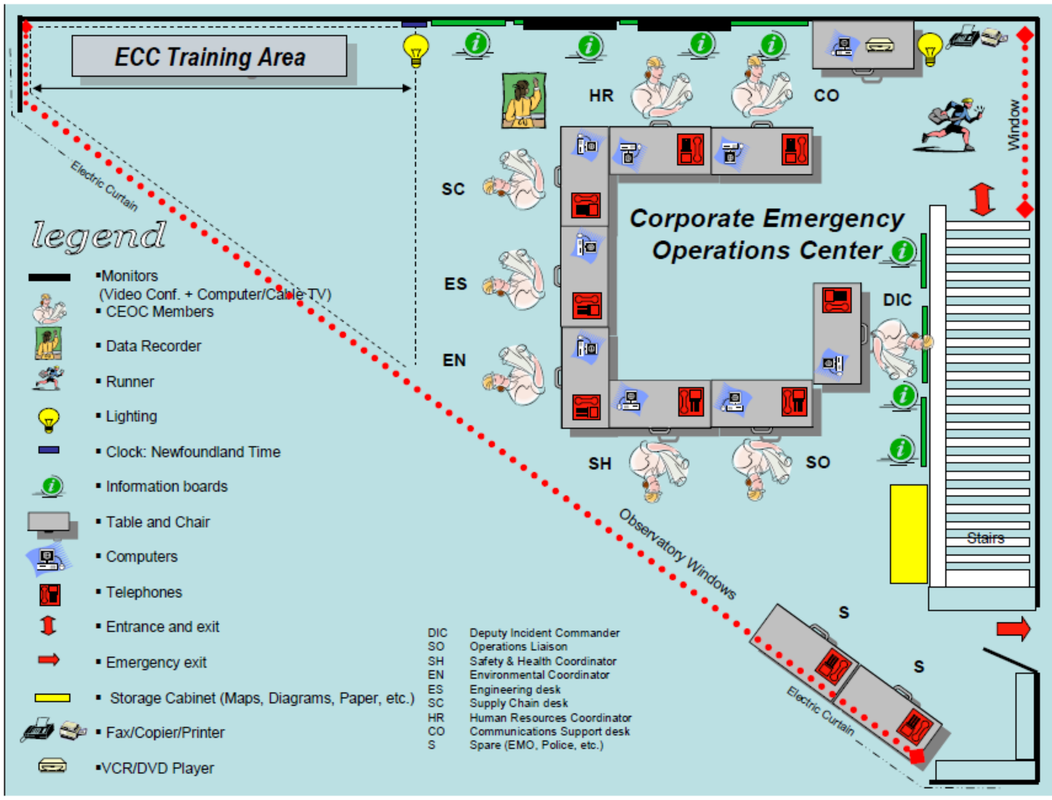
1. Emergency Operations Center

Hydro[160] uses Nalcor's Corporate Emergency Operations Center ("CEOC") as its Emergency Operations Center ("EOC"). The Corporate Center sits in a room above Hydro's Energy Control Center, and has a viewing gallery that permits observation of both Energy Control Center activities and the static display board indicating real-time status of Hydro's transmission and generation systems. The Emergency Operations Center is sized and designed for specific roles

[160] Responses to RFIs #PUB-NLH-069 and 398.

during a Nalcor Corporate or a Hydro emergency. It is equipped with workstations designed for specific roles, and with communications equipment, white boards, computer equipment, and other equipment necessary for the management of an emergency. The next figure shows the layout of the facility.

Figure 8.1: Emergency Operations Center Layout



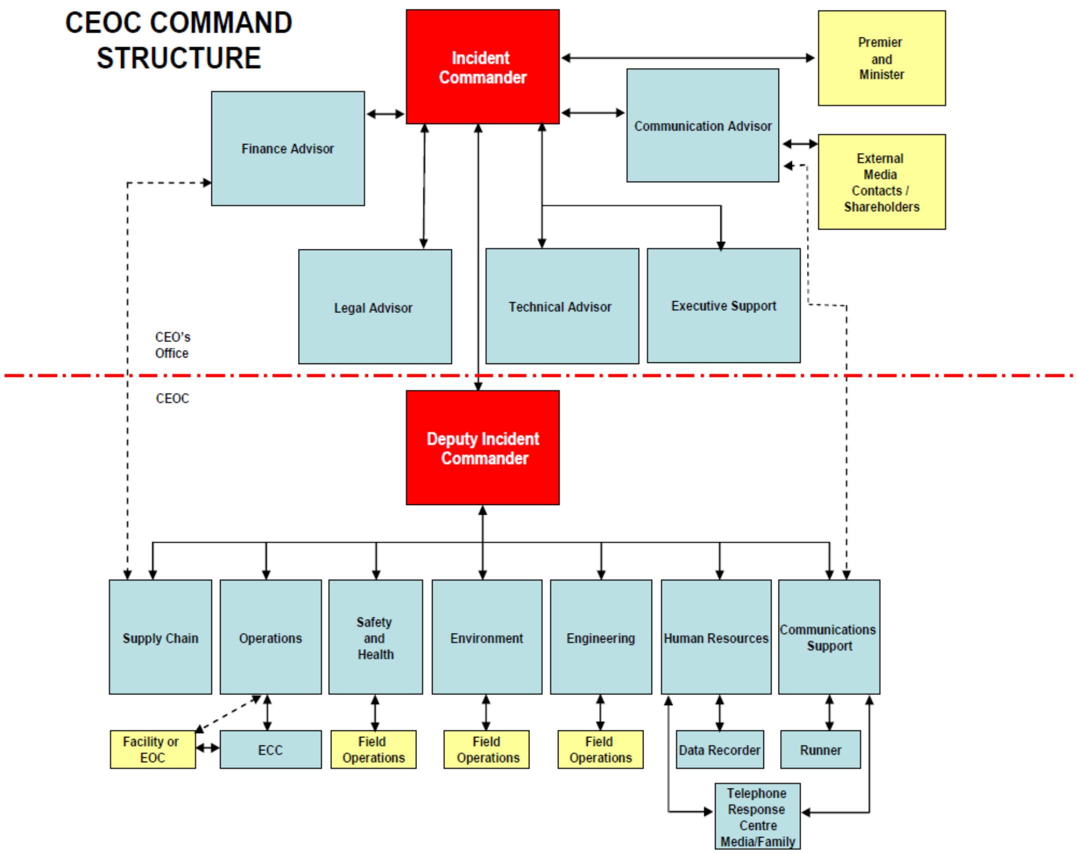
2. Emergency Response Organization

The declaration of an emergency activates the Emergency Operations Center.[161] The first team member arriving at the Center informs the Energy Control Center that the Emergency Operations Center has become operational. The Operations Liaison subsequently assumes responsibility for direct contact with the Energy Control Center, providing a source of two-way communications and ensuring accurate, timely updates to and from the Energy Control Center. The Manager, System Operations and Integration Support is the primary source for filling the role of Operations Liaison with the Energy Control Center Supervisor, with System Operations Engineering personnel serving as the primary alternates.

Emergency team staffing consists of the Incident Commander, Deputy Incident Commander, and Operations Liaison. The next figure shows the Emergency Operations Center Command organization.

[161] Responses to RFIs #PUB-NLH-069 and 398.

Figure 8.2: Emergency Team Staffing and Responsibilities



Nalcor's President and CEO, or other member of the Executive Leadership Team serves as Incident Commander. The commander provides overall strategy and direction and serves as liaison with Government. The Vice President, Newfoundland & Labrador Hydro serves as Deputy Incident Commander. This position advises the Incident Commander on incident status, and manages the Emergency Operations Center. The Manager of System Operations and Customer Service serves as Operations Liaison. This position maintains contact:

- To acquire and exchange information related to response operations
- With the Deputy Incident Commander concerning status of the emergency
- With Newfoundland Power and with other Hydro customers as required.

Advisory and support roles have been established for the following areas:

Finance	*Technical*	*Executive Support*
Communications	*Legal*	*Safety & Health*
Environmental	*Engineering*	*Supply Chain*

3. Nalcor's Emergency Plan

Hydro operates under Nalcor's CERP, but has its own Severe Weather Preparedness Protocol.

a. Purposes

To address emergency situations throughout Nalcor's enterprises, the parent corporation employs a 93-page CERP, first issued in 2008. Nalcor's most recent update came in November 2013, and included updated emergency contact lists.[162] The cited purpose of Nalcor's plan[163] is to provide clear and concise guidance for emergency support actions to be taken under scenarios that could reasonably be expected to occur. Nalcor has produced a plan that addresses the parent corporation's response to emergencies at whatever subsidiary they might occur. Nalcor's plan does not seek to address specifically how Hydro internally responds to severe storm, generation shortfall, or equipment failure-caused emergencies. Nalcor's plan therefore comprises a high-level document that:

- Covers a reasonable range of potential events, but not in detail
- Defines the roles of Nalcor executives and key managers
- Defines communication protocols within Nalcor and with other external agencies operating in areas where emergencies could occur
- Sets forth roles and responsibilities for each emergency function, including checklists to aid the responsible manager(s)
- Provides samples of required documentation and reports that need to be completed during and after emergencies
- Includes agreements between Hydro and Newfoundland Power regarding mutual assistance and major storm response.

The Nalcor plan defines an emergency as any unexpected occurrence that results in or has the potential to lead to death, injury or illness requiring hospitalization, environmental impact posing a serious threat to on-scene personnel or wildlife, major and significant damage to Nalcor or other property, or "significant public impact." The response to such incidents requires immediate notification and action. Examples of emergencies include:

- An incident that could result in loss of life or a serious injury (*e.g.*, vehicle collisions, lost personnel, etc.)
- Explosions or major fires
- Loss of power system equipment resulting in a supply interruption that could exceed the "Maximum Acceptable Downtime" (which is not a defined term)
- Well-control incidents and hydrocarbon or chemical spills
- Loss of or damage to helicopters or fixed wing aircraft
- Hazards, such as weather, posing imminent threat to the operating area
- Significant damage to equipment caused by other factors (*e.g.*, materials handling equipment failure)
- Security-related incidents (*e.g.* extortion, bomb threats, terrorism).

The Nalcor CERP assigns specific responsibilities to Nalcor individuals for the provision of support services during emergencies. The Plan's procedures permit these individuals to mobilize the corporate response and to execute emergency support actions.

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[162] Nalcor web site www.nalcorenergy.com. *And* Response to RFI #PUB-NLH-069.
[163] Response to RFI #PUB-NLH-069.

b. Declaring an Emergency

The CERP indicates three levels of Emergency Response based on the following classification:

- **Level 1:** Minor local emergencies managed on-scene and in coordination with local response agencies; support from the Emergency Operations Center not required
- **Level 2:** Major local emergencies managed on-scene and in coordination with local response agencies; full or partial support from the Emergency Operations Center required
- **Level 3:** Catastrophic emergencies that cannot be managed on-scene even with support from local response agencies; full support from the Emergency Operations Center required.

In circumstances where the person declaring the emergency is unsure whether an event is Level 1 or Level 2, the emergency is treated as Level 2 and the Emergency Operations Center is therefore activated. In circumstances where the person declaring the emergency is unsure whether an event is Level 2 or Level 3, the emergency will be treated as Level 3 and the Corporate Emergency Operations Center is activated.

Any Manager can declare an emergency, and initiate the sequence of emergency plan actions when concerned that actual or pending situations warrant this level of corporate attention. Managers are encouraged to be proactive, and not to fear “penalties” for alerts that turn out to be less than full emergencies. Currently, a pager system initiates the response using one of three codes:

- A *711* code is used weekly, when the on-call rotation takes place, to test the pagers and to ensure that those on the roster are engaged. All recipients must respond to the page via e-mail.
- An *811* code is used when a manager believes that an Emergency may be pending, or is uncertain about the severity of the situation. Senior Nalcor and Hydro managers assess the situation and determine if there is a need to stand down, to continue to monitor the situation, or to declare an emergency.
- A *911* code is used to declare an emergency. The response processes and the personnel call outs detailed in the CERP are initiated.

The Energy Control Center sends alerts to the emergency team for Hydro emergencies. Hydro[164] however is evaluating an external smart phone program application that would enable assignment of notification responsibility to a third party, to relieve the Energy Control Center of this task. The pagers would be replaced with cell phones.

c. The January 2014 “Emergency”

Beginning in late December 2013, Hydro became aware that loads on the IIS, increasing due to extremely cold weather coupled with reduced generation availability at both Hydro and Newfoundland Power, could lead to insufficient generation to meet load.[165] On January 2, 2014 this threat became reality, and a series of steps, outlined in Hydro’s Emergency Response Plan,

[164] Interview Systems Operations Manager, 10-Oct-2014.
[165] Response to RFI #PUB-NLH-002.

were taken. However, no formal declaration of an Emergency Event (a "911") occurred.[166] However, Hydro managers and employees were mobilized and according to Hydro management, both Hydro and Nalcor acted as though a formal declaration was made[167].

4. Severe Weather Procedures and Response to the January 2014 Events

For severe weather event forecasts or a system problem affecting the ability to meet system load, the Energy Control Center issues an advisory to field operations staff, and prepares for the event. Hydro[168] ensures staff availability at certain remote hydro plants and standby generation locations when potential generation shortfalls exist. Hydro's response may also include the following activities, depending on the expected severity of the event:

- Pre-event coordination call to coordinate response activities
- Enhanced staffing levels at Energy Control Center and other control rooms as needed
- Deployment of work crews to reduce response times
- Additional inspections of equipment and vehicles to ensure full functionality and gas tanks
- Additional communication with on-call personnel to ensure readiness to respond
- Scheduling of additional snow removal to ensure access to critical infrastructure
- Test run of standby diesels and gas turbines.

The next paragraphs compare actual actions taken during January 2014 with the seven response items.

a. Pre-event Coordination Call

Normal procedure[169] calls for System Operations (upon receipt of warnings from Environment Canada) to issue notices of weather warnings to regional and plant managers. System Operations then follows up with field operations staff to discuss any needs for additional preparations for the pending weather. Field staff then makes any further coordination calls needed to secure the power system.

The situation facing Hydro on January 3, 2014 warranted a broader and more comprehensive coordination call than the normal procedure would entail. Hydro was initiating rolling blackouts due the generation shortfall and a significant winter event was forecasted for the next day. An 11 a.m. coordination call among senior management, System Operations, Engineering, Transmission and Rural Operations, Hydro Generation, Communications and Holyrood Generation groups took place. Its purpose was to ensure that all groups were aware of the system status and to coordinate the response. The call emphasized the need to maintain the continuity of the existing generation infrastructure and to ensure prompt response to any system issues, in order to minimize customer impact. Resulting deployment of crews, extra snow clearing, and emergency preparation activities initiated on January 3 supported response to the outages experienced on January 4, 2014.

[166] Interview, 10-Oct-2014.
[167] Interview, 10-Oct-2014.
[168] Response to RFI #PUB-NLH-030.
[169] Response to RFI #PUB-NLH-068.

b. Enhanced Staffing Levels

Normal practice during significant disruptions to the power system and during times of high call volume to the Energy Control Center call for bringing in extra staff. The additional customer call volume requires extra staff, especially outside of normal working hours, when there may be a delay in mobilizing the Customer Service Call Center. Also, depending on the complexity of the issue, additional staff may be brought in to help manage the issue. Hydro does not record and log each time that additional staff is brought in to supplement control room staff.

On January 4-5, 2014, Hydro increased staff levels at the following control rooms:

- St. John's Energy Control Center
- Holyrood Thermal Generating Station
- Bay d'Espoir Hydroelectric Generating Station.

The increased staffing levels balanced the larger workload among operators, and provided redundancy for rest breaks to mitigate worker exhaustion and stress.

c. Deployment of Work Crews to Reduce Response Times

Advanced deployment of crews to specific sites prior to a storm provides benefits when the storm is predicted to occur in a particular geographical area, or there are known system equipment issues at those sites which may require attention during a storm. The benefits of keeping crews at their home bases and close to the center of operations often outweighs the risk of locating them at a remote location where problems may not occur. In the case of generating stations, the majority of Hydro's large hydro generating units are located in the Bay d'Espoir area or in Cat Arm and Hinds Lake. These locations lie close to the home base location of the work crews that support those facilities. Similarly, for Transmission and Rural Operations, Hydro's crews' home offices or depots have been located throughout the province in central locations with facilities to provide fast response to interruptions.

For these reasons, the deployment of work crews to specific sites other than their home offices in advance of a weather event is not a common activity, but is one that is considered in advance of each major forecasted weather event. For example, for the weather event forecasted on January 4, 2014, it was decided that it would be prudent to ensure crews were scheduled to report to key terminal stations on the Avalon Peninsula. As a result, an employee was on site at Sunnyside the morning of January 4, 2014, which expedited the response efforts.

d. Additional Vehicle and Equipment Inspections

Additional vehicle and equipment inspections are routinely performed for Transmission and Distribution areas. However, since the event of January 2013, these activities have been expanded to include all of Hydro operations in advance of any significant weather event. Prior to the severe weather events of January 4, 2014, Hydro Generation, Exploits Generation, TRO, Holyrood and Hydro Place staff ensured full functionality and full fuel tanks for all necessary equipment and vehicles. These activities help prevent delays in crew mobilization should the need arise.

e. Additional Communication with On-call Personnel to Ensure Readiness

These communications occur routinely in accordance with the operating instruction Notification of Weather Warnings and Lightning Activity. Hydro does not have records of call outs, but, on January 3, 2014, all on-call personnel were alerted of the impact of rolling outages and the threat posed by the forecasted winter storm.

f. Scheduling Additional Snow Removal to Ensure Access to Infrastructure

Hydro identified additional snow removal as an area where improvements could be made following the 2013 winter, when it experienced many delays in getting key personnel into Hydro Place and into the Holyrood Thermal Generating Station. Hydro now has snow clearing arrangements in place for all its facilities. Additional or priority snow removal requests made prior to January 4, 2014 storm include:

- Ongoing clearing of Upper Salmon road to ensure access to Upper Salmon Generating Station
- Ongoing clearing and extra sanding of Hinds Lake road to ensure access to Hinds Lake Generating Station
- Request to City of St. John’s to maintain access to Captain Whelan Drive as a priority, to ensure access to Hydro Place
- Request to the snow clearing contractor to maintain access to Holyrood Thermal Generating Station
- Priority snow clearing for access to Stephenville gas turbine.

g. Test Runs of Standby Diesels and Turbines

Hydro tests standby diesels and gas turbines monthly to ensure availability in accordance with operating instructions T-051 (diesels) and T-054 (gas turbines). Since the events of January 2014, Hydro has also started the practice of running up the gas turbines in Stephenville and Hardwoods and the standby diesels in Hawke’s Bay and St. Anthony in advance of significant forecasted weather events.

h. Lessons Learned

Hydro[170] undertook a review of supply issues and power outages associated with the January 2014 events. This initiative began after the completion of system restoration activities. Working sessions included several different focus areas: Holyrood, Gas Turbines, ECC, Hydro Generation, Exploits Generation, Transmission and Terminals, Corporate Communications, CERP, IT Support/Network Services, and Customer Services and Conservation. This lessons-learned initiative sought to identify what went well, what did not, and opportunities for improvement. Hydro has taken a number of actions as a result of this work.

First, Hydro observed that having crews at Granite Canal, Cat Arm and Sunnyside improved response to equipment problems in these stations during the January 2014 events. Based on that experience, Hydro deploys work crews to remote plants and terminal stations prior to the onset of severe storms to reduce response time in the event of weather-related unplanned equipment

[170] Response to RFI #PUB-NLH-043.

problems. It continually reviews and optimizes the deployment of crews based on forecast storms.

Second, Hydro observed issues with the Stephenville Gas Turbine during the event. More frequent starting and running of the standby generation prior to severe weather will be undertaken to allow time to identify and correct issues to ensure plant availability when required. Hydro will review this practice following this winter to determine effectiveness.

Third, Hydro observed the existence of diesel fuel supply problems throughout the Province during this event. Hydro's supplier had difficulty in sustaining required deliveries for continuous gas turbine plant operation at Stephenville. In order to be prepared for sustained operation, as provincial supplies recover, Hydro will increase and maintain fuel inventory levels at gas turbine plants. Hydro will assess this practice following this winter to identify any issues associated with maintaining the larger inventories.

5. Hydro's Updated 2014 Severe Weather Preparedness Protocol

Hydro[171] updated its Severe Weather Preparedness Protocol on September 28, 2014. In the event that a severe weather event is forecasted, Hydro's Energy Control Center issues an advisory to field operations staff. For potential generation shortfalls, Hydro ensure that staff is dispatched to certain remote hydro plants and standby generation locations.

In the case of a severe weather event, Hydro's response includes any or all of the following activities, depending on the expected severity of the event:

- Pre-event coordination call to coordinate response activities
- Enhanced staffing levels at ECC and other control rooms as needed
- Deployment of work crews to reduce response time in the event of an unplanned outage or equipment problems
- Additional inspections of equipment and vehicles (four wheel drive trucks; snowmobiles, ATVs and specialized vehicles) to ensure full functionality and full gas tanks
- Additional communication with on-call personnel to ensure readiness to respond if needed, and
- Scheduling of additional snow removal to ensure ongoing access to critical infrastructure during storm events; and/or test run of standby diesels and gas turbines.

Hydro's[172] September 28, 2014, Severe Weather Preparedness Protocol incorporates lessons learned from the 2013 and 2014 outages. The Protocol defines the detailed steps required for minimizing the impact of severe weather. It also includes a severe weather preparation checklist, instructions on notifying parties of severe weather and lightning, and instructions on preparing diesel and gas turbine generators for storm emergencies. Hydro also includes actions for preparing for generation shortfalls.

[171] From Appendix C to "An Update Report to the Board of Commissioners of Public Utilities Indicating the Winter Readiness Status of Hydro's Generation Assets," dated October 1, 2014.
[172] Integrated Action Plan, Reference No. 76. September 28, 2014.

There is a mutual aid agreement between Hydro and Newfoundland Power. However, there are no other inter-utility mutual aid agreements in place with utilities from other provinces.

6. Severe Weather Management Duties

Hydro's[173] Severe Weather Preparedness Protocol assigns the following duties for addressing severe weather conditions:

- Hydro's Senior Management and Executives:
  - Set expectations for safety, reliability, and operational performance
  - Ensure that a winter weather preparation procedure exists for each operating location
  - Consider annual winter preparation meetings and training exercises to share best practices and lessons learned from the previous year.
- Hydro's Regional Managers and Plant Manager:
  - Ensure on-call supervisor awareness of pending storms
  - Evaluate storm forecast and determine need for deployment of employees
  - Ensure contact information availability for Protection and Controls Engineering for possible evaluation of fault traces
  - Ensure proper execution of winter weather preparation procedure
  - Conduct plant readiness review prior to an anticipated weather event
  - Following each winter, evaluate effectiveness of the weather preparation procedure
  - Ensure equipment and vehicle inspection completion prior to forecasted events.
- Hydro's Energy Control Center:
  - Communicate storm forecasts to operational managers and follow up with field operations staff
  - Ensure test runs of standby generation
  - Contact Newfoundland Power for generation status update
  - Determine if stand-by generation will be started prior to peaks and consult with Transmission and Distribution to determine if Operators need to be on site
  - Augment Center staffing as needed.

7. Other Relevant Practices and Procedures

Hydro's[174] Emergency Operating Center begins analyzing and tracking adverse weather five days out for estimating impact on electrical systems and on service to customers. For coming events judged to potentially have severe impact, an advisory goes to field operations staff. A conference call may take place among System Operations, Project Execution and Technical Services, and Operations. A number of tasks need to be completed to prepare for the expected weather. Some everyday operational tasks completed by field operations also assist with increased weather event response:

- Fleet vehicle fuel-up at the end of each working day
- Equipping on-call supervisors with all emergency plans, employee contact information, and a corporate vehicle

[173] From Appendix C to "An Update Report to the Board of Commissioners of Public Utilities Indicating the Winter Readiness Status of Hydro's Generation Assets," dated October 1, 2014.
[174] From Appendix C to "An Update Report to the Board of Commissioners of Public Utilities Indicating the Winter Readiness Status of Hydro's Generation Assets," dated October 1, 2014.

- Cell phone availability to various shops and the gas turbine operators
- Stocking shops, offices, and trucks with critical spares and consumables
- At-home vehicle access for distribution line workers and distribution front line supervisors.

Hydro provides a number of operating Instructions that address readiness for specific equipment-caused contingencies which may or may not be related to severe weather.[175] These Operating Instructions, not addressed in the October 28, 2014 Severe Weather Preparedness Protocol, include:

- Operating Standard Instruction 010: System Outages
- Operating Standard Instruction 042: Forest Fires Near Transmission Lines
- Operating Instruction A-003: Notification of Weather Warnings and Lightning Activity
- Operating Instruction T-001: Generation Loading Sequence and Generation Shortages (now titled Generation Reserves)[176]
- Operating Instruction T-007: Holyrood Black Start Restoration using Hardwoods Gas Turbines
- Operating Instruction T-032: Restoration Plan for Loss of TL202 and TL206
- Operating Instruction T-078: Hardwoods and Oxen Pond Restoration
- System Operating Instruction T-042: Rotating Outages.

Hydro has also started the practice of running up the gas turbines in Stephenville and Hardwoods and the standby diesels in Hawke's Bay and St. Anthony as required in advance of significant forecasted weather events. By testing and proving the full operating capability of standby generating units in advance, it allows Hydro to ensure that these assets will provide reliable service under peak load or generation shortfall conditions and during power system emergencies.

Per North American Reliability Corporation guidelines, Hydro includes evaluations of potential problems (similar to a root cause analysis to prevent what could happen) including identifying and prioritizing components, systems, and other areas of vulnerability which may experience freezing problems or other cold weather operational issues. This includes equipment that has the potential to:

- Initiate an automatic unit trip
- Affect unit start-up
- Affect environmental controls that could cause full or partial outages
- Affect the delivery of fuel or water to the units
- Cause other operational problems such as slowed or impaired field devices
- Create a weather related safety hazard.

Hydro also lists typical cold weather problem areas, based on previous cold weather events. Managers review plant designs and configurations, identify areas with potential exposure to the elements, ambient temperatures, or both, and tailor plans to address them accordingly. Hydro

[175] Response to RFI #PUB-NLH-054.
[176] Response to RFI #CA-NLH-008.

included a long list of possible problem areas in its Processes and Procedures, including ensuring that black start and emergency generators will be available,

Other winter-readiness practices include:

- Managers coordinate[177] annual training in winter-specific and plant-specific awareness and maintenance training, including testing of emergency response plans and equipment specific training.
- The Asset Owners Technical Council holds winter readiness meetings on an annual basis to highlight preparations and expectations for severe weather.
- Operations personnel review applicable emergency response plans in the Environmental Management System and Safety and Health Program prior to December 1.
- Operations personnel ensure all equipment specific training is up to date.

8. Winter Preparedness and Emergency Drills

The Energy Control Center[178] conducts two or three training exercises per year for outage/storm training, using the simulator station and mock interaction with field forces, under the guidance of the instructor. Hydro[179] also conducts preparatory drills of emergency response plans on an annual basis as part of its winter preparedness plans. Following the incidents of December 2013 and January 2014, Hydro updated its Severe Weather Preparedness Protocol. Hydro also used the conditions experienced during this past winter to enhance on-going training efforts and future drills to ensure personnel with responsibilities in the CERP are prepared for similar occurrences.

The following Emergency Practice Drills and related activities were conducted, or are scheduled to be conducted prior to the 2014/15 winter season:

- The CERP was exercised on May 16.
- Hydro is testing a new mobilization/call out process using Telelink to replace the usage of pagers. Two planned exercises by December will test the Telelink system, to mobilize the emergency response team, and to review participant roles and responsibilities.
- System Operations scheduled its annual Energy Control Center evacuation and Backup Control Center activation for October 2014.
- Hydro conducted an exercise with Newfoundland Power on joint outage communication protocol.
- Transmission & Rural Operations drilled its Environmental Emergency Response Plan on July 14, 2014.
- Fire drills are conducted annually at all facilities; *e.g.,* the TRO Bishops Falls complex on May 21, 2014 and Holyrood plant on August 14, 2014.
- Holyrood scheduled Industrial Fire Fighting training for emergency response technicians at the Marine Institute.
- Transmission and Rural Operations and Holyrood high angle rescue responders practice regularly.

[177] From Appendix C to "An Update Report to the Board of Commissioners of Public Utilities Indicating the Winter Readiness Status of Hydro's Generation Assets," dated October 1, 2014.
[178] Response to RFI #PUB-NLH-195.
[179] Response to RFI #PUB-NLH-396.

- A mock exercise of an extreme weather event was completed through Hydro Generation.
- Pre-runoff testing of reservoir spill gates was completed in the spring of 2014.
- Oil spill response drills are held annually.
- Hydro Generation exercises its Emergency Preparedness Program for response to potential dam and dyke breaches annually, as part of the overall Dam Safety Program.
- Intake bubbler systems and water uplifters are test run as a normal element of fall preparations by plant operators.
- Plant black start procedures are reviewed.
- Communications systems are checked.
- The Severe Weather Preparedness checklist was tested on summer storms.

9. Rotating Outage Procedure

Hydro[180] formalized its rotating outage procedures based on lessons-learned from its review of the January 2014 events. Following is Hydro's *Rotating Outage Procedure*:

> 1. Request Newfoundland Power to shed load by rotating feeders. Advise them of the expected generation deficit, the expected duration of the rotations, and that the frequency needs to be maintained at 59.8 Hz.
>
> 2. Inform Corporate Relations and Customer Services that rotating outages will commence and that each feeder rotation will last one hour.
>
> 3. Refer to the Feeder List to determine the feeder to be interrupted and the order in the rotation.
>
> 4. Open the appropriate feeder (remotely or locally) and record the time in the ECC diary. For feeder rotations completed locally, ECC will dispatch crews to the station and direct the operation.
>
> 5. When one hour has elapsed, open the next feeder on the Feeder List (remotely or locally) and record the time in the ECC diary.
>
> 6. Restore the previously opened feeder (remotely or locally) and record the time in the ECC diary.
>
> 7. Throughout steps 4-6, monitor the system frequency and maintain communication with NP (Control Room) and with Corporate Relations and Customer Services. Advise Newfoundland Power if there are any concerns with system reliability (frequency and voltage) and provide updates to all stakeholders on the status of the generation deficit.
>
> 8. Continue steps 4 through 7 until there is no longer a generation deficit and the system frequency is stable at 59.8 Hz.
>
> When rotating outages are no longer required, restoration of disconnected feeders will be completed as follows:
>
> 1. Advise Newfoundland Power that rotating outages are no longer required and remaining load restoration can begin shortly.

[180] Response to RFI #PUB-NLH-397.

2. Inform Corporate Relations and Customer Service that rotating outages are no longer required and load restoration will begin shortly.

3. Coordinate the restoration of any remaining load between both utilities. Load should be restored in 20 to 25 MW blocks while maintaining system frequency.

The IIS employs 44 feeders. Each was evaluated for use in the rotating outage process. This evaluation identified 31 feeders subject to interruption. The remaining feeders will not be interrupted for the following reasons:

- Given priority due to the customers being supplied by the feeder.
- Not feasible to send crews to locations as the load on the feeders is very low and would not be material.

10. Inter-Utility Communication Process Improvements

The following items summarize Hydro's communication and coordination activities with Newfoundland Power to prepare for the upcoming winter peaking season: [181]

- The Inter-Utility System Planning and Reliability Committee ("IUSPRC") meeting frequency has increased. The committee, made of up senior leaders from Hydro and Newfoundland Power in the areas of Operations and Planning, normally meets twice per year. Thus far in 2014, the utilities have met in May, June, July and September. The meetings focus on action items related to asset and winter readiness.
- Hydro and Newfoundland Power share real-time data between control Centers to facilitate coordinated operations and response to disturbance events on the power system. By July of this year, Hydro approved, implemented and verified with Newfoundland Power the transfer of some 400 additional points over the data link, from Hydro's EMS to Newfoundland Power's SCADA system.
- Operations managers from both utilities have been regularly sharing the status and progress of asset maintenance, additions and replacements. This includes Hydro's major equipment such as Oxen Pond transformers T1 and T3, Sunnyside transformer T1, Western Avalon transformer T5, Transmission Lines TL201 and TL203 and the new Holyrood combustion turbine.
- The utilities have discussed the timing of the Newfoundland Power generation credit test. Both agree that the test to prove the Newfoundland Power generation capacity is better performed prior to December 1.
- Planned equipment outages required by both utilities are coordinated to minimize the impact to power system reliability and customer service. Hydro targeted completion of all critical equipment outages prior to December 1.
- Hydro shared with Newfoundland Power its new instruction dealing with the Island generation supply ratings and capacity. This instruction, titled Island Generation Supply - Gross Continuous Unit Ratings, is used to keep an account of available generating capacity on the Island Interconnected System. The instruction specifies the requirement for testing at various time intervals to confirm generating unit capacities. The instruction also requires that asset owners communicate to Hydro's Energy Control Center the status

[181] Response to RFI #PUB-NLH-397.

and capacity of generating units. This instruction is important to the maintenance of adequate generation reserves. Hydro and Newfoundland Power discussed and agreed to an approach on how Newfoundland Power will update Hydro, on a daily basis, of the status and capacity of Newfoundland Power's hydro and thermal generation fleet. Both utilities derived a common understanding regarding Hydro's requests for the use of Newfoundland Power's hydro generation and its standby thermal generation.

- Hydro shared with Newfoundland Power its modified instruction that deals with Island generation reserves. This instruction titled, Generation Reserves, was developed with input from Newfoundland Power. This instruction details the requirements of Hydro in assessing the available IIS generation reserves and communicating to stakeholders when available generation reserves fall below prescribed thresholds, or levels. Aligned with this instruction, both utilities have developed a common communications strategy to inform key external stakeholders, including customers, when generation reserves are below these defined thresholds. Hydro and Newfoundland Power have worked collaboratively to ensure appropriate understanding and expectations.
- Based on a discussion with Newfoundland Power on their lessons learned around rotating outages, Hydro has documented a procedure (T-042) for handling rotating outages on its distribution system.
- Hydro has kept Newfoundland Power informed of its progress in the area of short term load forecasting and the approach Hydro is taking regarding the forecasting of Island Interconnected generation, rather than the traditional Hydro System only approach.
- Hydro and Newfoundland Power corporate communications teams have worked on several items including the development of a joint storm/outage communication process and an advance notification process for advising customers of conservation requests and rotating power outages. Significant research has been conducted with customers and businesses in the province to help guide the development of communications strategies.
- Hydro and Newfoundland Power corporate communications teams have been meeting on a weekly basis throughout the fall to formalize and implement education and communication plans to inform customers on conservation activities and the advance notification protocol. In addition, formal testing of the joint storm/outage communication process occurred this fall.

11. 2014 Integrated Action Plans Related to Emergency Management Actions

Hydro has been regularly reporting progress in completing items recommended in Liberty's 2014 Interim Report and items required by the Board in its Interim Report. Hydro included these recommendations as well as actions it identified in an Integrated Action Plan and has reported progress on the work undertaken to implement all the recommended actions as listed in the Integrated Action Plan. The first progress was submitted to the Board on May 2, 2014. Hydro has been reporting progress on a number of actions listed in the Integrated Action Plan related to Emergency Management.[182] Hydro reports all those actions as completed. Liberty reviewed progress in completing them as of December 10, 2014. Liberty did not verify actions by field review, but relied upon Hydro's status reports and discussions with management. Liberty

[182] Response to RFI #PUB-NLH-394.

addresses the results of our review below, using the item numbers of Hydro's Integrated Action Plan.[183]

a. *No. 55: Complete all outstanding work in relation to the Hydro Place emergency generation system, and report to the PUB outlining availability risks and revised maintenance procedures.*

Hydro reports this item as complete.

b. *No. 56: Execute a 2014 plan for ensuring there is adequate emergency lighting in Hydro Place.*

Hydro reports this action as complete. Hydro has installed emergency lighting in Hydro Place stairwells, and made improvements in generator room emergency lighting.

c. *No. 57: Ensure that documents related to system restoration, including cold start procedures, are readily available in the IIS office and in the Hydro Place Energy Control Center in hard copy format.*

Hydro reports work completion as of April 2014.

d. *No. 58: Implement a process for the monitoring of critical alarms from the Hydro Place Uninterruptible Power Supply (UPS) on a real-time 24/7 basis.*

Hydro reports this item as complete, with alarms are now monitored, and appropriate personnel notified.

e. *No. 64: Document and streamline the internal processes used for sharing and distributing information between System Operations and Corporate Relations in a potential supply disruption/outage situation. Due date: 30-Sep-2014*

Hydro reports this item as complete. The System Operations Manager participated in an Issues Analysis exercise with internal stakeholders to develop a streamlined process for communications during outages. TRO, CCC and Energy Control Center staff have been trained.

D. Conclusions

8.1. The Nalcor/Hydro Emergency Operations Center location, contents, and the assigned staffing duties conform to good utility practices.

Hydro uses Nalcor's Corporate Emergency Operations Center as its Emergency Operations Center. This Center is located in a room above Hydro's Energy Control Center. The room has a viewing gallery that permits observation of activities of the Energy Control Center and the static display board. This board indicates the real-time status of Hydro's transmission and generation systems. When activated, the Corporate Emergency Operations Center is appropriately staffed and its personnel have clear roles for managing all types of emergencies and for communicating with the Energy Control Center and stakeholders during a declared emergency.

[183] Updated Integrated Action Plan as at the end of September, 2014.

8.2. Hydro's Corporate Emergency Response Plan is generally sufficient, but does not give managers guidance in determining whether to classify an outage event as minor, major, or catastrophic. (*Recommendation No. 8.1*)

When a Hydro emergency is declared, Nalcor and Hydro implement Nalcor's CERP. This plan provides guidance for opening the Emergency Center and for initiating Emergency Support actions to Hydro in the event of an emergency causing significant public impact, or causing a loss of power system equipment that results in a supply interruption that could exceed the Maximum Acceptable Downtime. However, the Plan does not help in determining how to classify an outage event.

The CERP is very thorough. The Plan defines an emergency as any unexpected occurrence resulting in or having likely potential to cause death, injury or illness requiring hospitalization, environmental impact posing a serious threat, major damage to property, or significant public impact. It allows any manager to declare and classify an emergency as a minor, major, or catastrophic emergency. The Plan includes "loss of power system equipment that results in significant supply interruption that could exceed the Maximum Acceptable Downtime" as an emergency. The Plan however does not define maximum acceptable downtime. An emergency declaration did not occur during the catastrophic January 2014 events.

8.3. Hydro's Severe Weather Preparedness Protocol is generally sufficient, but does not fully address certain matters. (*Recommendation #8.1, 8.2, and 8.3*)

Hydro's Severe Weather Preparedness Protocol prescribes the assignment of duties and preparatory actions taken in advance of approaching severe weather. The Protocol, however, does not address Restoration Protocols for: (a) assessing storm damage, (b) assigning levels of activity based on the magnitude of equipment damage and customer outages, (c) providing emergency living quarters and meals for crews, when necessary, (d) protecting the public from downed lines, and (e) prioritizing restoration of terminal stations, substations, and feeders. The Protocol does not require the assignment of an Emergency Level as described in the Corporate Emergency Response Plan (minor, major, or catastrophic), based on the potential impact (numbers of customer interruptions) of the approaching severe weather, for the purpose of determining the nature of preparedness required. Also, Hydro's Severe Weather Preparedness Protocol does not include any references to the uses of its various restoration-related Operating Instructions which may apply to Severe Weather Conditions. For example, Operating Standard Instruction T-001: "Generation Reserves" may be important when the severe weather is prolonged very cold weather.

8.4. Hydro provides a number of Operating Instructions that address readiness for specific equipment-caused contingencies that may or may not be related to severe weather.

These Operating Instructions provide instructions related to generation shortfalls, system equipment outages, rotating outages, forest fires, weather warning and lightning activity, and restoration procedures for Holyrood, Hardwoods, Oxen Pond, and Lines TL 202 and TL 206.

8.5. Hydro conducted 2014/2015 winter preparedness exercises, drills, and tests in recognition of lessons-learned from previous winters, and has enhanced and formalized communications with Newfoundland Power.

8.6. Hydro completed all of its emergency preparedness, communication, and coordination Integrated Action Plans Items.

E. Recommendations

8.1. Include in the Corporate Emergency Response Plan and in the Severe Weather Preparedness Protocol guidelines for determining how to classify a predicted or actual outage event as minor, major, or catastrophic in terms of numbers of customer interruptions or customer interruption hours, as a minor, major, or catastrophic emergency for determining preparedness requirements. *(Conclusion Nos.8.2 and 8.3)*

8.2. Develop a Restoration Protocol, in addition to the Severe Weather Preparedness Protocol, to address: (a) assessing storm damage, (b) assigning a Storm Level of activity based on the magnitude of equipment damage and customer outages, (c) providing emergency living quarters and meals for crews, when necessary, (d) protecting the public from downed lines, and (e) prioritizing restoration of terminal stations, substations, and feeders. *(Conclusion No. 8.3)*

8.3. Include references in the Restoration Protocol to the uses of the various restoration-related Operating Instructions which may apply to Severe Weather related restorations. *(Conclusion No. 8.3)*

IX. Customer Service and Outage Communications Issues

A. Background

Liberty performed a review of Hydro's progress addressing outage communications recommendations arising from Liberty's April 24, 2014 Interim Report. Liberty's Interim Report contained eight recommendations that jointly concern Newfoundland Power and Hydro, one specific to Hydro, and one specific to Newfoundland Power. Hydro has undertaken initiatives to improve outage communications and inter-utility coordination in response to the nine recommendations that concern it. Seven of the nine initiatives have been completed. Hydro plans to complete the two yet underway by the end of 2014.

#	Recommendation	Status
37	Develop Joint Outage Communications Technology Strategy	Complete
38	Conduct Joint Customer Outage Expectations Research	Complete
39	Stress Test any Enhancements to Customer-Facing Technologies	Complete
40	Refresh Business Continuity Plans and Contingencies	In Progress
41	Pursue Multi-Channel Communications	In Progress
42	Develop Advance Notification Communications Protocols	Complete
44	Develop Storm/Outage Communications Plan	Complete
45	Conduct a Joint Lessons-Learned Exercise	Complete
46	Create Executive-Level Committee to Guide Initiatives	Complete

This chapter reviews Hydro's reported progress in addressing these nine recommendations.

Island Industrial Customers also raised concerns in their comments following the issuance of Liberty's Interim Report, identifying the need to be well informed of planned and unplanned outages impacting their operations. Liberty investigated further to better understand Hydro's customer research and communications to support its large commercial and industrial accounts (key accounts). The results of this additional investigation are contained in this chapter as well.

B. Chapter Summary

This chapter reviews Hydro's reported progress in addressing recommendations to improve outage communications. In the days since the January outage event, Newfoundland Power and Hydro have worked individually and jointly to tackle outage communications issues and improve inter-utility coordination.

A joint executive-level committee coordinated efforts, and facilitated joint cooperation in resolving issues, including the creation of an advance notification protocol to guide decisions and communications during times of reduced generation reserves. Newfoundland Power and Hydro also conducted a joint lessons-learned session to discuss opportunities to improve inter-utility coordination and communications. A Joint Communications Plan was created to encourage coordinated and consistent communications during anticipated or actual outage events and both utilities tested the new plan through a joint supply shortage tabletop exercise. Seven of the nine initiatives have been completed, two are underway, due to be completed by the end of the year.

Hydro has a well-established and communicated set of six Company Values. Customer service or customer satisfaction is one of the six values. Hydro's Customer Service Department has reported to Nalcor's Customer Relations Department since November 2011. Liberty's 2014 Interim Report, however, found that Corporate Relations had yet to develop a customer service strategy for the department to guide day-to-day service response or customer service response during outages. In September 2014, Hydro published its Customer Service Strategic Roadmap,[184] which sets forth a "vision for improving service to Hydro's industrial, utility and retail customers." This is a key first step. However, the funding required to achieve the strategic initiatives outlined in the plan has not been addressed to date.

Hydro does not have a key accounts customer service team dedicated to serve its largest customers. Rather, Hydro's industrial customers are served and supported largely by the System Operations Department. While Customer Service is responsible for issuing the bills for industrial customers, communication and coordination is largely the responsibility of System Operations, including communications related to planned and unplanned outages. Hydro acknowledged this gap in the recently published Customer Service Strategic Roadmap.

C. Findings

1. Joint Outage Communications Technology Strategy

Liberty's recommendation stated:

As a first step, Newfoundland Power and Hydro should develop an Outage Communications Strategy to prioritize opportunities and guide near- and longer-term improvements to customer contact technologies and telephony, beginning with preparation by June 15, 2014 of a detailed plan and schedule for doing so.

Hydro finalized a Customer Service Strategic Roadmap[185] in September. This document describes plans to enhance and improve customer service related technologies over the next three years. Near-term initiatives include revising outage protocols and formalizing after-hours telephone support. In addition, Newfoundland Power and Hydro have discussed possible synergies for shared customer contact and outage communications technologies, especially as Hydro faces replacement of its customer information system, revisions to its customer service pages on its website, and upgrades to its call center telephony over the next few years.

Work to address this recommendation has been reported as completed.

2. Joint Customer Outage Expectations Research

Liberty's recommendation stated:

Hydro and Newfoundland Power should conduct customer research (primarily on a joint basis), in order better to understand customer outage-related informational needs and expectations, including requests for conservation, and to incorporate

[184] Response to RFI #PUB-NLH-202.
[185] Response to RFI #PUB-NLH-202.

results into the Outage Communications Strategies, beginning with preparation by June 15, 2014 of a detailed plan and schedule for doing so.

Hydro and Newfoundland Power jointly conducted customer research over the summer to understand customer expectations regarding outage-related communications. They conducted a number of surveys:

- Telephone survey of 800 residential customers
- Focus groups to explore preferences in St John's, Carbineer/Sunnyside, Central Newfoundland, and Rocky Harbor
- Online survey of 100+ business customers.

Results from this customer research highlighted the need to provide increased education on the ways customers can conserve, including businesses. Additionally, customers shared expectations on how soon Estimated Time to Restoration (ETRs) should be provided, how often they should be updated, and how much time is needed to prepare for a potential outage event. This information has been used to revise outage communications and storm preparation protocols.

Work to address this recommendation has been reported as completed.

3. Stress Testing Technology Enhancements

Liberty's recommendation stated:

As Newfoundland Power and Hydro move forward with enhancements to any customer-facing outage support systems, each should stress test the technologies well prior to the winter season; this element should comprise a key component of their implementation processes.

Hydro has committed to stress testing any future changes to its website and telephony. Hydro's strategic plan targets replacement of call center technology over the next two to three years.

4. Refreshing Business Continuity Plans and Contingencies

Liberty's recommendation stated:

Hydro should review and refresh business continuity plans and contingencies to ensure continual operation and availability of critical outage response support systems, beginning with preparation by June 15, 2014 of a detailed plan and schedule for doing so.

Hydro has contracted with a consultant to review its business continuity plans. A final report is due by the end of 2014. Hydro will implement any necessary recommendations following receipt of the final report. Additionally, a Call Center specific business continuity plan is being developed to ensure continued operations of the contact center should a situation compromise operation of the center or its supporting technologies.

Hydro reports this work as underway, with expected completion in the fourth quarter of 2014.

5. Multi-Channel Communications

Liberty's recommendation stated:

> *Newfoundland Power and Hydro should pursue (primarily on a joint basis) other multi-channel communication options, such as two-way SMS Text messaging or Broadcasting options, for delivering Outage Status Updates, beginning with preparation by June 15, 2014 of a detailed plan and schedule for doing so.*

Hydro has plans to replace its self-service outage communications technologies over the next two to three years, including its website, contact center telephony, and customer service system. In the meantime, Hydro and Newfoundland Power are collaborating to determine possible synergies and opportunities for Hydro to leverage Newfoundland Power's front-facing technologies in the future, as Hydro considers options for replacement.

6. Advance Notification Communications Protocols

Liberty's recommendation stated:

> *Newfoundland Power and Hydro should aggressively pursue a joint process for delivering advance notification for planned rotating outages, in order to facilitate good initial communications with customers during an outage event, beginning with preparation by June 15, 2014 of a detailed plan and schedule for doing so.*

Newfoundland Power and Hydro have jointly developed an advance notification protocol to guide customer communications when generation reserve margins are expected to dip below predetermined thresholds. Hydro modified its T001 protocol to project a shortfall in generation reserves in stages of severity:

- 0-Normal (5-day forecast greater than largest generating unit plus minimum spinning reserves)
- 1-Power Advisory (5-day forecast less than largest generating unit plus minimum spinning)
- 2-Power Watch (24-hour forecast indicates reserves less than largest generating unit)
- 3-Power Warning (Current day reserve margin is less than half of the largest generating unit)
- 4-Power Emergency (Generation shortfall imminent, no reserve margin).

Stakeholders will be notified based on the forecasted severity. Customer notifications guidelines have been established to guide the release of public information for each stage and determines the point at which customers will be asked to conserve electricity and when advisories should be issued to prepare customers for rotating power outages, should they be required.

Work to address this recommendation has been reported as completed.

7. Storm Outage Communications Plan

Liberty's recommendation stated:

Hydro and Newfoundland Power should jointly develop a coordinated, robust, well-tested and up-to-date Storm/Outage Communications Plan documenting protocols, plans, and templates to guide communications during major events, beginning with preparation by June 15, 2014 of a detailed plan and schedule for doing so.

Newfoundland Power and Hydro have developed a Joint Communications Plan[186] to guide customer communications during significant outages or events. The Joint Outage Communications Plan provides clear guidelines and templates for major events that result in damage to or interruption of power supply to the Island Interconnected System. The Plan is intended to ensure that the Utilities are the primary authoritative voice during a critical incident that affects either Company's operations. It enables both Corporate Communications Teams to quickly activate, and provides strategies, tools and templates to effectively communicate to customers, employees, media and key stakeholders during outage situations.

The plan was successfully tested through a tabletop scenario drill in September 2014. Individuals representing operations, management, and communications from both utilities were involved in the testing exercise. The test of the Plan was successful—both utilities were prepared to handle the scenario and the Plan guided communications at all levels. The Joint Communications Plan will be updated as needed to capture any changes to the process, including any lessons learned from future outages or storms. Additionally, Hydro and Newfoundland Power have committed to testing the plan annually.

Work to address this recommendation has been reported as completed.

8. Joint Lessons-Learned Exercise

Liberty's recommendation stated:

Newfoundland Power and Hydro should conduct a joint "lessons-learned" exercise including both their Communications Teams, beginning with preparation by June 15, 2014 of a detailed plan and schedule for doing so.

The Communications Teams from Hydro and Newfoundland Power conducted a joint "lessons-learned" session on May 20, 2014 to review the January outage event. The joint session included individuals from customer service, operations, and energy efficiency. Discussions covered the January events as well as initiatives underway following the event. Discussion focused on ways to work jointly to address issues, ways to share information, planned improvement initiatives, and customer research.

Both utilities plan to conduct similar joint lessons-learned sessions following any future events.

Work to address this recommendation has been reported as completed.

[186] Response to RFI# PUB-NLH-304, Attachment 1.

9. Executive-Level Committee to Guide Initiatives

Liberty's recommendation stated:

> *Hydro and Newfoundland Power should commit to a formal effort, sponsored at their most senior executive levels, to work together in formulating joint efforts to identify goals, protocols, programs and activities that will improve operational and customer information and communications coordination, leading to the development, by June 15, 2014, of identified membership on joint teams, operating under senior executive direction and according to clear objectives, plans, and schedules.*

An executive-level committee of senior managers from both utilities has been meeting monthly to oversee joint recommendations, discuss action items, and coordinate activities.

A key accomplishment of the executive committee was the joint development of the Customer and Stakeholder Advance Notification Protocol (refer to recommendation #42 in the Interim Report). These meetings were used to further the discussions around stakeholder information needs as well as the thresholds guiding the release of information. These discussions established the foundation for the Joint Communications Plan (refer to recommendation #44 in the Interim Report).

This committee was also key in expanding the level of real-time status information available between Hydro and Newfoundland Power concerning the status of lines, equipment, and generation. Additionally, short-term load and generation information is being made accessible to Newfoundland Power, which will determine the timing of customer communications during a projected shortfall.

Subsequent meetings defined the need to jointly test the advance communications protocols and the Joint Communications Plan. A successful tabletop drill was ultimately conducted in late October.

This committee also served as a forum to discuss ways to improve operational coordination as well as discuss progress on other joint recommendations, including the customer research, multi-channel outage communications, and technology stress testing. While many of the action items subsequently have been completed, these meetings continue on a monthly basis to address any issues requiring inter-utility cooperation.

Work to address this recommendation has been reported as completed.

10. Customer Service Follow-up

Hydro's Customers Service Department reports to Nalcor's Vice President of Corporate Relations. This organization has been in place since November 2011. Prior to this, the Customer Service Department reported to Hydro's Vice President of System Operations. Hydro's Customer Service Department is comprised of five functions:

Table 9.1: Customer Service Department Functions and Staffing

Function	Staffing
Call Center	6 FTEs and 2 Temps
Meter Reading	3 FTEs
Billing	14 Meter Readers
Technical Support	2 FTEs
Revenue Metering & Quality Assurance	3 FTEs and 1 Temp

Hydro's Call Center handles 50,000 customer calls, 6,000 emails, and 3,500 service requests annually. The billing team issues more than 400,000 customer bills annually for residential, commercial, and industrial customers. Hydro operates a call center, staffed with a lead customer service representative, five customer service representatives, and during seasonal peaks, two temporary workers.

The Customer Service Department does not support Hydro's largest customers. Rather, Hydro's key accounts are supported through Systems Operations. Hydro does not have a key accounts customer service team dedicated to serving its largest customers. While Customer Service is responsible for preparing the bills for industrial customers, System Operations reviews and approves each bill prior to issuance. Systems Operations is also responsible for all communication and coordination with industrial customers, including communications related to planned and unplanned outages. Systems Operations coordinates daily with these customers for any outages affecting the system. Additionally, Systems Operations meets annually with each customer for system planning.

11. Customer Satisfaction Research

Hydro has conducted an annual customer opinion survey, through the assistance of an external service provider, for several years. Additionally, Hydro participates in the CEA's public attitude survey.

Hydro's annual customer opinion survey focuses primarily on residential and small commercial customers. Hydro's industrial and large commercial customers are not surveyed. Hydro does not routinely conduct transactional customer satisfaction surveys of specific interactions with the utility, a common practice within the utility industry. Aside from the focus groups conducted over the summer, Hydro has not conducted any recent customer research using focus groups or customer panels.

Annual customer surveys measure customer attitudes and opinions and try to gauge overall customer satisfaction. Transactional surveys measure satisfaction with a recent contact or interaction. Transactional surveys and focus group research provide more actionable feedback that can be used to improve business processes, modify service offerings, and coach and develop employees.

D. Conclusions

9.1. Hydro has reported significant progress on the outage improvement recommendations, with remaining work on track for completion.

9.2. Hydro's largest customers are served and supported largely by the System Operations Department, not the Customer Service Department. (*Recommendation No. 9.1*)

Hydro does not have a key accounts customer service team dedicated to serving its largest customers. Rather, Hydro's industrial customers are served and supported largely by the System Operations Department. While Customer Service is responsible for issuing the bills for industrial customers, communication and coordination is largely the responsibility of System Operations, including communications related to planned and unplanned outages.

Hydro's largest customers have a direct line into the Energy Control Center. System Operators are responsible for all communications with these customers, including coordinating the best possible time for planned outages. System Operations is also responsible for contacting these customers during any unplanned outages. This includes contacting customers ahead of a storm with weather forecasts. Hydro's operating instructions contain guidelines on when alerts are issued to customers.

Hydro does not track its daily communications with industrial customers. Most utilities use customer-relationship management systems to track interaction with key accounts.

Hydro acknowledges this gap in its recently published Customer Service Strategic Roadmap, where it stated: "We see an opportunity to improve relationships and processes with our large account commercial and industrial customers by implementing an account management program."

9.3. Hydro's Customer Satisfaction Surveys have focused on residential and small commercial customers. *(Recommendation No. 9.2)*

Hydro's annual customer satisfaction survey focuses primarily on residential and small commercial customers. Hydro's industrial and large commercial customers are not surveyed for customer satisfaction. Additionally, Hydro relies on annual attitudinal customer research and does not conduct transactional customer satisfaction surveys nor does it gather customer research through focus groups or customer panels.

E. Recommendations

9.1. Hydro should develop a key accounts management program to support and serve large industrial and commercial customers. *(Conclusion No. 9.2)*

While it's important for System Operations to coordinate with its large industrial customers concerning supply decisions, customer account and service issues and concerns would be better handled by customer service professionals. Hydro's Customer Service Department should develop a key account management program to focus on customer relations for its largest customers. Key Accounts management teams are common within the utility industry and are generally tasked with relationship building, communications, and supporting customer energy management needs. Most key account management teams utilize customer relationship management (CRM) software to manage communications and track interaction.

A strategic account plan (expectations, needs, plans, preferred communications channels, contacts) can be developed for each key account to document and align customer and utility expectations. Plans can be documented within the CRM system and should be updated annually with each customer.

Hydro should also consider expanding its tabletop drills testing outage communications processes to include key account personnel. Inclusion of key industrial accounts in these practice sessions will improve the communication and coordination between Hydro and its largest customers so that each party is better prepared for any future events.

9.2. Hydro should conduct customer research to better understand its largest customers. *(Conclusion No. 9.3)*

Hydro should investigate ways to include its key customers in customer research to ensure that it stays in tune with customer expectations. This research can be gathered formally through surveys, focus groups or customer panels and will supplement the informal feedback gathered through the key accounts program.

X. Governance and Staffing

A. Background

The Board requested that Liberty review Hydro's "governance and decision making" among the matters for examination for this report. Liberty examined the board governance structure and also looked at the executive level organization. In addition, Liberty examined the overall resource structure that Nalcor uses to provide asset management, project management, and technical services to Hydro, among its other business areas.

B. Chapter Summary

Liberty examined Hydro's governance model, including the composition and structure of the board of directors and management. Liberty did not conclude there was a direct link between the 2014 power supply outages and the governance model, but did identify a number of recommendations to enhance the effectiveness of the governance framework and to support a strong focus on Hydro's utility operations. These recommendations reflect best practices in governance that are common in the North American utility sector.

Applying that common model would call for the appointment of directors that sit only on the Hydro board (and not the Nalcor board) and would expand the breadth and depth of skills and experience to ensure effective board oversight of Hydro's operations, including its opportunities and risks. Ideally, a director with very senior level power industry operating experience (from the electricity sector, if available) should be appointed. Hydro should also develop a program to increase board understanding of and engagement in annual planning processes and in discussions on service quality, infrastructure conditions, and operational performance. Application of this model would also entail detailed reporting to the board, so as to allow appropriate engagement of the board in these matters.

Hydro operates with what they describe as a matrix organizational structure. Services among all entities in the Nalcor group that are shared include executive management, operations support and corporate and administrative services. While the provision of common services can produce efficient and cost effective use of resources, Liberty found certain aspects of Hydro's structure uncommon. With respect to executive management, all Hydro functions report to a President and CEO who also serves Nalcor and its other lines of business. Given the scope of the CEO's responsibilities in this structure, limited time exists for overseeing Hydro's operations. It is uncommon in the utility business for generation, transmission design, operation, customer service and regulatory affairs to be brought together only at the level of the holding company CEO. It is also uncommon to assign multi-business–line responsibility to an executive for design, project management, asset management and technical services as Hydro does with the Project Execution & Technical Services division that provides support to all Nalcor's lines of business.

Liberty recommends that a new position be created to consolidate responsibilities for all the functions central to the infrastructure and operations systems that deliver service to the IIS. Liberty believes this to be a priority. Liberty also concludes that an executive position should be created for the management of regulatory affairs, in order to ensure that regulatory requirements and expectations form a more central and strategic role in senior leadership's planning, overseeing, evaluating, and taking responsive action to emerging issues that have implications for stakeholders and the regulator. Liberty also recommends that Hydro advance efforts it has taken to date to develop, establish and implement an effective enterprise risk management system.

C. Findings

1. Governance

Nalcor and Hydro have separate boards of directors. The two boards, however, have identical membership. The boards of directors of other Nalcor business lines share membership entirely or mostly in common with the parent (Nalcor) board. Some, however, have directors who bring backgrounds particularly applicable to the nature of those businesses.

Common practice in our experience with North American utility holding company structures (of which the predominant number are in the United States) is to employ largely or totally common boards for the parent and the utility. A variation is to reside material leadership and oversight of the holding company and utility matters in the holding company board, while constituting a utility board of internal directors who perform routine, more administrative functions. Where, as here, non-utility operations are very sizeable in relation to utility operations, distinct boards for major operating entities do use the approach of largely common membership between the holding company and the subsidiaries, with some members unique to the differing entities.

It is also common now to see the use of more formal approaches, (*e.g.*, skills and experience matrices) that lay out the broad range of personal attributes and experience diversity recognized as contributing to the optimum provision of oversight at the director level of utility operations that have become increasingly more dynamic and complex. Directors, generally working with the top executive management then use those matrices, in conjunction with candid, regular self-assessments of board performance to match current board membership with the recognized range of personal attributes and skills diversity appropriate to meeting oversight needs. Board candidate recruitment then focuses on candidates that will enhance the match between identified needs and membership skills and experience as a whole.

The nature of Nalcor's share ownership differs from most typical models (*e.g.*, investor-owned and cooperative, or member-owned, enterprises). Government or public ownership brings with it the need to determine what model to apply to oversight of the management given responsibility for running the business(es) involved. One model treats the business as essentially an operating department of government, with oversight coming from the government department(s) or organization(s) most directly involved with the interests affected by operations. Another model has a separate board with responsibility for providing the same governance as the board of a large business entity.

Liberty's discussions with executive management generally confirmed that the governance function is intended to reside in a largely independent board of directors interacting with Nalcor management as one would generally expect to see in the world of large business operations. The purpose of Liberty's review was not to recommend a particular model, but rather to assess how the application of the model already selected can best serve utility service needs with reasonable efficiency and effectiveness. Liberty believes that a largely independent board, interacting with management in a manner typical of large utility operations, presents the best structure for optimizing performance. Liberty's understanding is that this is the model intended to be in place at Hydro.

Areas of divergence from best practices under this model and what exists at Hydro include:

- Lack of a concentrated effort to appoint directors according to a structured view of optimum skills and experience needed for the nature of Hydro's operations
- Lack of promotion of a time and effort commitment that supports board engagement in a depth commensurate with a dynamic and complex operating environment and management of risks
- Not ensuring that board compensation supports expectations about the time and effort required to remain abreast of board challenges and requirements, understand company performance in meeting them, and to guide and hold management accountable for optimizing that performance.

2. Executive Organization Structure

The first executive level at which all functions relevant to Hydro's electric generation and transmission functions come together is at the level of the President and CEO, who serves Nalcor in a similar capacity.[187] Nalcor has a number of other lines of business; they include:[188]

- Churchill Falls: The second largest North American underground hydroelectric plant, with 11 turbines totaling 5,428 megawatts
- Oil and Gas: Holder and manager of oil and gas interests in Newfoundland and Labrador, engaged in a partnership in three offshore developments and an interest in a fourth, and pursuing an "active exploration strategy designed to enhance knowledge and accelerate exploration activity in the province's numerous onshore and offshore petroleum basins"
- Lower Churchill Project: Consisting of the 824 MW Muskrat Falls Project now under development (along with Labrador-Island and Maritime Links that will connect to Nova Scotia) and a second phase, which encompasses development of a 2,250 MW Gull Island generation facility and associated transmission
- Bull Arm: Atlantic Canada's largest industrial fabrication site, located close to international shipping lanes and Europe, and providing deep water ocean access to service North Sea, Gulf of Mexico and West African developments
- Energy Marketing: Focusing now on marketing and trading surplus energy in Canadian and U.S. markets, and developing a future strategy for employing existing and future electricity and offshore oil and gas assets
- Other Generation Operations: (a) the Ramea project, which integrates generation from wind, hydrogen and diesel, (b) Exploits River hydroelectric facilities, managed and operated on behalf of the provincial government, and (c) Menihek Generating Station.

[187] Response to PUB-NLH-424.
[188] http://www.nalcorenergy.com/nalcor-at-a-glance.asp

Some of the other lines of business (*e.g.*, Oil and Gas and Lower Churchill Project) have their own, single lead executives (vice presidents) reporting to the Nalcor President and CEO. Hydro faces the need to integrate the organizations operating Hydro and the Lower Churchill Project's first phase as it approaches completion. In contrast to those of Nalcor's other business lines that operate under a consolidating executive, two separate vice presidents, each with paramount roles in the operation of Hydro's generation and transmission systems report separately to the Nalcor President and CEO, in the latter's exercise of a similar capacity for Hydro. A third Nalcor executive oversees a large team engaged primarily in performing key design, project management, asset management, and technical services for Hydro (a role filled to a lesser extent in terms of resources for Nalcor's other lines of business). These three officers are the:

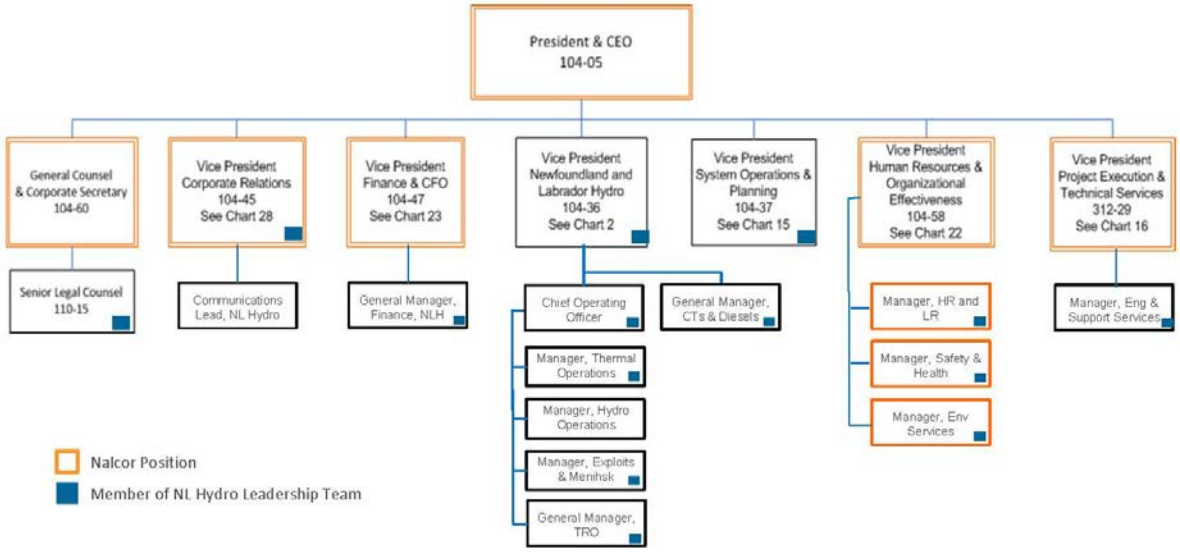
- Hydro Vice President
- Hydro Vice President of System Planning & Operations
- Nalcor Vice President of Project Execution & Technical Services (serving Hydro's needs as well as those of other Nalcor business operations).

Other key Hydro leadership positions are held by executives who operate on a Nalcor-wide basis. The executive responsible for overall direction of customer services is the Vice President, Corporate relations. The executive who provides overall direction for regulatory affairs is the Nalcor Vice President Finance and CFO.

It is uncommon for an operation like Hydro's to bring executive responsibility for generation and transmission design, operation, customer service, and regulatory affairs together only at the level of a holding company CEO. Also fairly uncommon is the assignment of multi-business-line responsibility for the executive heading design, project management, asset management, and technical services (what Hydro terms Project Execution & Technical Services).

The next chart illustrates the Hydro organization. It shows that Nalcor executives fill for Hydro (as they do for other Nalcor lines of business) a number of finance and administrative functions. Common leadership and staffing of such functions is common in industry holding company structures.

Chart 10.1: Nalcor/Hydro Executive Structure



3. Commonly Provided Services

Determining net resources provided to Hydro from its own and Nalcor-based resources requires an accounting for Hydro time charged to others and charges by others to Nalcor. One way to capture those resource levels is to show the number of full-time equivalent Hydro personnel after adjusting for time charges in and out, and for allocations of commonly provided corporate services. The next table does so for recent years, with the 2014 numbers representing forecasted resources.[189] The drop from 2010 to 2013 amounts to somewhat over 1 percent, followed by a substantial increase for 2014.

Table 10.2: Equivalent Hydro Resources

Year	Number
2010	789
2011	784
2012	776
2013	779
2014 Forecast	832

Liberty inquired into the nature and level of common services provided by Nalcor personnel or under the direction of leadership by Nalcor executives and senior managers. The creation of a structure for providing services in common to Nalcor's multiple lines of business (including Hydro) has a fairly recent vintage. Liberty's focus lay on ensuring that the use of a common services approach did not cause Hydro a lack of timely and fully sufficient resources to address the planning, design, maintenance and operations of the generation and transmission assets necessary to ensure adequate and reliable service across the IIS.

[189] Response to PUB-NLH-466.

The matrix approach employed by Nalcor to serve Hydro and its other lines of business include common support in areas that are generally classified as administrative and general, and which one finds commonly provided in holding company structures.[190]

Given the nature and resource levels for many of these functions performed under the direction of executives in common among Hydro and other Nalcor business areas, Liberty did not deem a review of their personnel numbers and organization or their activities necessary. The senior executives leading these functions had designated dedicated Leads to support Hydro in the Rates & Regulatory, Controller, Supply Chain, Legal, Communications, Safety & Health, and Environmental Services areas.

Liberty did look more closely at two of the common support functions directly related to Hydro's generation and transmission operations; *i.e.,* Supply Chain management and financial functions associated with Hydro budgeting and cost control. Hydro has a dedicated (home-based) staff of 24 that has operated under the Nalcor Manager of Supply Chain Management. This manager is the only non-Hydro home-based Supply Chain position. A similar approach exists for the finance, controller, and regulatory positions in Hydro. A Hydro home-based staff under three managers operates under Hydro's General Manager, Finance to perform these three functions, leaving the Vice President of Finance and CFO as the only Nalcor home-based employee engaged in these Hydro functions.[191] The Hydro regulatory group has five positions under the Manager, Rates and Regulatory.

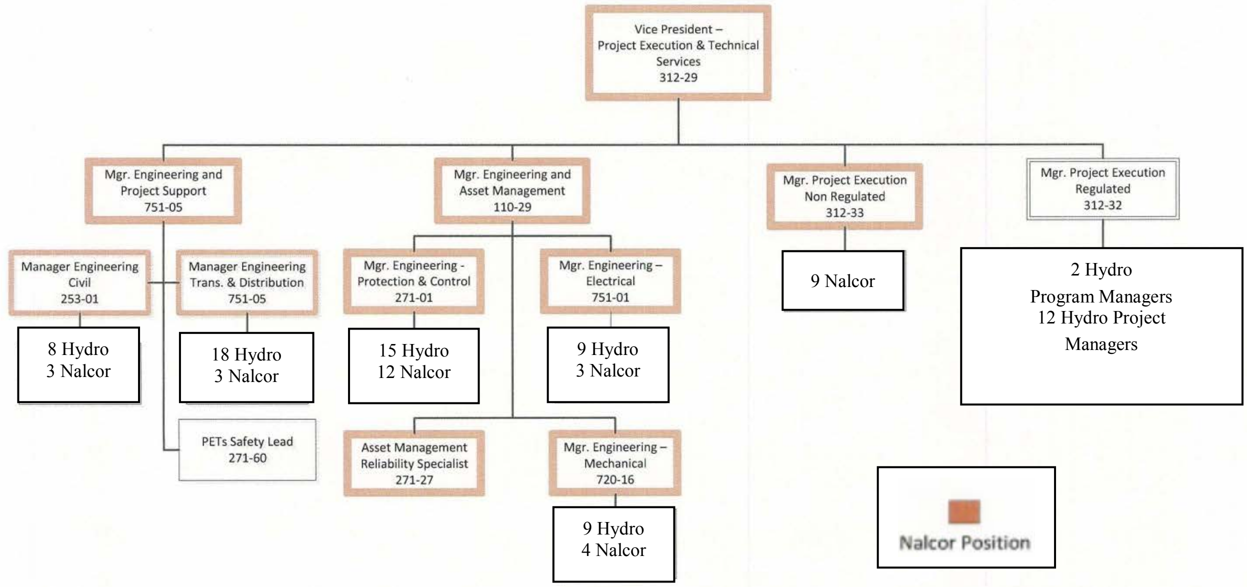
Liberty did not examine the costing methods used to ensure that no cross-subsidization of costs occurs. That issue requires detailed analysis and verification outside the scope of our engagement. Liberty sought rather to examine whether access by Hydro to the resources needed to support the generation and transmission assets and infrastructure might be impaired by the use of a common services approach. Liberty therefore concentrated on the organizations and resources under the:

- Hydro Vice President
- Hydro Vice President, System Operations & Planning
- Nalcor Vice President, Project Execution & Technical Services.

Substantial sharing of resources occurs in Project Execution & Technical Services. The following chart below shows the group's overall organization.[192] The outlined positions are Nalcor home-based. The others are Hydro-home based. The table's five-digit numbers reflect department codes, not staffing.

[190] Response to PUB-NLH-424.
[191] Response to PUB-NLH-427.
[192] Response to PUB-NLH-427 and 463.

Chart 10.3: Project Execution & Technical Services Organization



The next table shows the percentages of each position charged to Hydro in recent years.

Table 10.4: PETS Personnel Time Charged to Hydro

Area	Position	Year 2011	Year 2012	Year 2013
Electrical Engineering	Electrical Engineer			14.6%
	Electrical Engineer		45.1%	5.4%
	Manager Engineering Electrical	38.9%	47.1%	21.8%
	Electrical Engineer	39.5%		
Mechanical Engineering	Mechanical Engineer			1.5%
	Manager Engineering Mechanical	29.2%	16.5%	20.6%
	Mechanical Engineer		73.6%	75.1%
	Co-op Engineer			26.8%
Asset Management	Manager Technical Services and Asset Management	19.0%	36.7%	38.9%
Protection	Manager Engineering Protection and Control	9.7%	18.5%	12.7%
	Sr Protection and Control Engineer	13.8%		
	Protection & Control Engineer		55.1%	137.2%
	Communications Engineer			58.2%
	Communications Engineer		23.9%	56.1%
	Communications Engineer		5.7%	68.6%
	Protection & Control Engineer			46.5%
	Protection & Control Engineering Specialist			44.0%
	Protection and Control Engineer		1.2%	
Project Execution (Non-reg)	Project Planner/ Scheduler	13.4%	34.5%	16.5%
	Accountant			22.7%
	Project Manager			5.2%
	Project Manager			1.9%
	Manager Project Execution (Non-regulated)	0.7%	0.2%	1.9%
	Senior Civil Engineer		1.9%	
	Co-op Engineer			2.5%
	Owner Site Representative			1.6%
Civil Engineering	Manager Engineering Civil	35.1%	24.3%	50.9%
	Civil Engineer	65.6%		
	Civil Engineer			7.2%
Drafting	Drafting Services Supervisor	62.5%	66.0%	63.8%
T & D Engineering	Transmission Design Engineer			86.7%
	Transmission Design Engineer			16.9%
	Manager Engineering Transmission and Distribution	60.3%	67.0%	51.8%
	Manager Engineering Research and Development	43.7%	58.8%	60.6%
	Transmission Engineer	74.5%		
	Mechanical Engineer	0.6%		
	Plant Engineer- Menihek	2.5%		

Source: Response to PUB-NLH-426

4. Level of Shared Resources

Nalcor assigns employees to a particular entity (or "home base"). Hydro can report on a full-time equivalent ("FTE") basis those employees home based in Hydro who charge other entities.[193] It can also report on a similar basis the home-based employees outside Hydro who charge time to Hydro. The net of these two numbers provides one view of the level of time by general work type that Hydro provides to and is provided by others. This form of reporting, however, does not capture time charged through an "administration fee," as opposed to the direct recording of time spent by employees serving outside their home base entity. The following below shows the "Outs" (time that Hydro home-based employees charge affiliates) and the "Ins" (time that employees not home-based in Hydro charge Hydro). The figure demonstrates that the amount of charging is moderate on an overall basis, given these magnitudes. Totals may vary due to rounding.

The numbers charged out by Hydro's regulated operations (which includes the Hydro Generation, System Operations, and Transmission & Rural Operations groups) are relatively small. The next table shows what percentages regulated operations employees charging out from Hydro represent in relation to: (a) all Hydro employees charging out, and (b) total employees home-based in Hydro.

Figure 10.5: Hydro Regulated Operations Charges Out to Affiliates

(Full Time Equivalent Employees)

Year	2007	2008	2009	2010	2011	2012	2013
Regulated Ops Outs	1	2	4	4	6	6	7
Total Hydro Outs	20	19	27	32	35	26	28
Percentage	*5%*	*11%*	*15%*	*13%*	*17%*	*23%*	*25%*

Source: Response to PUB-NLH-422

The number of Hydro home-based Project Execution & Technical Services employees charging other entities has been significantly higher.

5. Regulatory Affairs

Nalcor's financial organization contains the regulatory affairs function that supports Hydro. It operates under the overall direction of Hydro-based General Manager of Finance. This general manager reports to Nalcor's Chief Financial Officer, who serves Hydro in a similar capacity. The reports to the General Manager of Finance included, until July of 2014, the:[194]

- Rates and Regulatory Manager
- Supply Chain Manager
- Electric Utilities Divisional Controller.

A July reorganization eliminated the Divisional Controller position and placed several other positions under the Hydro-based General Manager of Finance:

- Regulatory Engineering Manager
- Financial Controls, Processes, and Risk

[193] Response to PUB-NLH-422.
[194] Response to PUB-NLH-424.

- Financial Controller.

The Rates and Regulatory Manager has direct responsibility for regulatory affairs at Hydro. Before the July 2014 reorganization, this manager had five reports:
- Regulatory Coordinator
- Rates and Regulatory Team Lead (to whom two analysts reported, one for Rates and Regulatory and one for Rates and Financial Planning)
- Regulatory Engineering Manager.

The July 2014 reorganization divided these resources between the Rates and Regulatory Manager and the Regulatory Engineering Manager (formerly reporting to, but now lateral to the Rates and Regulatory Manager). This Rates and Regulatory Manager now has two direct reports (a Senior Financial Planner position that is currently vacant and a Revenue and Rates Analyst). Two other positions (Regulatory Coordinator and RSP and Capital Analyst) are shared with the Regulatory Engineering Manager. The net resources have not changed (but for the matter of filling the vacant Financial Planner position).

The structure that existed before and after the July 2014 reorganization places the highest-level person dedicated to Hydro regulatory affairs two notches below the officer level. Moreover, it creates a reporting line that does not tie directly to a senior Hydro-dedicated officer, but rather through a Nalcor/Hydro common CFO, whose reporting is to the Nalcor CEO. Moreover, the July 2014 change reduces the scope of duties under the responsibility of the highest-level person dedicated solely to Hydro regulatory affairs.

Liberty cannot directly tie the approach to or structure of regulatory affairs at Hydro to service reliability consequences. However, these matters do have implications for management of regulatory processes that concern reliability and for understanding the expectations of stakeholders in that process. Providing senior leadership with an effective, empowered source of communication to and from regulators and stakeholders and with a source of directly informed insights about expectations, opportunities, threats, and options forms an important priority. It offers a critical link in how senior leadership thinks about, faces, and responds to issues surrounding reliability and a number of other issues for which there exists requirements, expectations, and a wide range of potential plans and actions to meet them.

Liberty has found common in the industry the consolidation of regulatory affairs responsibility at a more senior level than exists at Hydro. At present, the only sources of such responsibility at Hydro exist at the second level below the executive team. Moreover, the lines of authority do not run through, but are parallel to, the most senior officers solely dedicated to Hydro's operations.

6. Enterprise Risk Management

Nalcor began formally to address risk management from an "enterprise" perspective three or four years ago. It progressed in 2013 to operations under a fairly comprehensive, draft "Enterprise Risk Management Policy Statement and Framework."[195] Fall 2013 corporate planning work led

[195] Response to PUB-NLH-417.

to the decision to bring in a manager dedicated to the enterprise risk management program's further development and implementation. At that point the Nalcor Treasurer (who performs a similar function for Hydro as well) led the program. Nalcor brought in the dedicated manager in 2014. Enterprise risk management remains within the Nalcor finance function, operating under the overall leadership of the Nalcor Chief Financial Officer. The Treasurer remains involved in Risk management; the new risk management head reports to that position.

The new Chief Risk Officer has a background in accounting and auditing, and significant experience in risk management. One of the immediate tasks is to review the statement and the structure of risk management. Current emphasis includes working with business unit leadership at Nalcor's entities, including Hydro, to update the risk framework and tool sets for analyzing risk and forming mitigation plans. The goal is to complete that work by the end of 2014.

The draft policy calls for an annually conducted process that systematically identifies, evaluates, treats, reports, and monitors line-of-business and strategic level risks through the application of tools in common across Nalcor's operations, including Hydro. Consistent with emerging practice, accountability for risk management resides with the heads of each line of business, with structure and process support from the Chief Risk Officer and Internal Audit. The draft document also reflects industry best practice in seeking to make risk management an embedded part of the planning process at the corporate and line-of-business levels and to develop a structured system for key-risk control and reporting.

The draft document describes a set of processes and tools that we consider generally commensurate with Hydro's needs. Liberty's particular area of more detailed focus was the degree to which risk management at Hydro: (a) addresses operational risk, and (b) incorporates the results of risk management processes into planning and budgeting processes.

Earlier risk management programs in the industry tended to focus more on financial and reputational risks, as opposed to operational ones. This more narrow focus reflects the origins of such programs in utility operations whose energy market operations often created very large risk in these areas. Current thinking recognizes the need to consider operating risk just as carefully, and the forefront of developmental efforts now are attempts to use quantitative measures of risk and mitigation as central elements of planning and budgeting. As recent outage events demonstrate, the operation of Hydro's generation assets and transmission infrastructure indeed do impose very substantial risk for the residents served from the Island Interconnected System.

Hydro's draft document cites "Operational" risk as the first of four risk categories addressed, the others being Strategic, Financial and Compliance. The draft document begins its detailed discussion of the elements of risk management by focusing on the need for direct expression of risk "appetite" (*i.e.*, the levels of risk that the entity is willing to accept). This expression reflects a strength of the Nalcor approach, but the discussion focuses on measurement of risk tolerance or appetite in terms of financial impacts, such as income volatility and credit rating. There should also exist a clear statement of the appetite for risks of adverse customer impacts (both safety and reliability). Similarly, the draft document's sections on identifying and addressing risks that emerge during the year contains clear identification of financial risks (and assigns legal and treasury group responsibility for examining them). In contrast, while the document refers to the need to consider emerging operational risk, it provides no clear means for such examination. The section requiring the establishment of a list of risk metrics provides descriptions of four financial risk metrics, but then only generally describes the need for metrics in the single item lumping Operational, Compliance, and Strategic risks together.

Vice presidents of the lines of business are expected to identify and ensure mitigation of risks within their spheres. The draft document refers to assistance in doing so by a risk management "representative" for their line of business.

The draft document requires incorporation of mitigation strategies into the five-year business plan, but does not contain detail specifying how this integration will occur and be manifested.

The draft document employs a fairly typical register of risks, identifying them, their "owner," mitigation strategy, and risk level remaining after implementing the risk mitigation strategy. It does not identify the capital and expense items and amounts involved, however. It does not permit a review of the degree to which spending associates with risk. Even the descriptors of risk significance (or impact) for Business Excellence (the one of the five overall Corporate Goals most directly tied to service reliability) provide a great deal more definition and clarity regarding financial risk than they do risk of customer impacts.

A Nalcor Enterprise Risk Committee operates as a cross functional team under the direction of the Chief Risk Officer. The Committee exists to provide assistance in developing, implementing and maintaining, and in assisting the designated line of business risk representatives with risk registers.

D. Conclusions

10.1. After examining the Hydro board of directors in relation to the usual model for holding company structures, Liberty found a number of areas that can be changed to enhance its effectiveness. (*Recommendation No. 10.1*)

The areas where the Hydro board operation and structure is at variance with the normal model comprise:

- Concentrated efforts to appoint directors according to a structured view of optimum skills and experience needs
- Promoting a time and effort commitment that supports board engagement in a depth commensurate with a dynamic and complex operating environment and management of service risks
- Ensuring that board compensation supports expectations about the time and effort required to remain abreast of broad challenges and requirements, understand company performance in meeting them, and guide and hold management accountable for optimizing that performance.

The use of a skills matrix for directors already has some applicability at Nalcor. For some business operations, Nalcor has supplemented the Nalcor board members serving them by adding persons with backgrounds deemed beneficial in addressing particular needs. That is not the case, however, at Hydro, whose board membership is identical to that of the parent. The types of skills and experiences needed to correspond to the breadth of Hydro's operations and the nature of its stakeholders need not only to be identified, but action should be taken to augment the current board with members that have the backgrounds identified as appropriate to overseeing Hydro's operations.

The Hydro board is comparatively small, making a paced process of adding a wider range of skills and experience feasible. Liberty particularly considers very senior level power industry operating experience (from the electricity sector if available) a prime area for immediate consideration.

Liberty considers promoting a strong commonality between parent and utility boards (which has been the Nalcor/Hydro practice) to normally be a preferred approach. However, the significant differences in Hydro's operations (from physical, technological, risk/opportunity, regulatory, and other perspectives) as compared with those of Nalcor's other operations warrants consideration. That factor, along with the size of the operations and the risks and opportunities of some of those other businesses leads us to conclude that Nalcor should extend to Hydro the practice of appointing a small number of directors who serve only on the Hydro board. A number of two seems logical, given the current size of the Hydro board and the companion need for augmenting the breadth of the directors' backgrounds.

Liberty found that the Hydro board's normal activities and the regular reports it receives from management responsive to core responsibilities. The scope and depth of the information it receives and the frequency and length of its meetings, however, correspond much more closely to more traditional than to current notions of the depth and breadth of board engagement. This conclusion holds for both the information scope and content, the matters of apparent discussion at meetings, and the frequency and length of meetings.

Best board practice now includes substantial engagement in (as opposed to a focus only on sign-off) annual planning processes and more detailed reporting on and engagement with management on service quality, infrastructure condition, and operational performance. The Hydro board's calendar for 2015, for example, schedules only five meetings, and the references to substantive work items outside of typical audit, financial reporting, and capital budget approval focus on "Business Unit Reports." Liberty's review of those issued in recent years found them limited in scope and depth with respect to best practice reporting and engagement.

Liberty's review of meeting schedules, minutes, and attendance indicated a lesser level of engagement opportunities with senior management than Liberty typically sees. In seeking a greater level of engagement, one must recognize the need to ensure adequate compensation for the time and effort it takes to perform at a level consistent with best practices. Experience compels the conclusion that it takes more than nominal or comparatively very low compensation to keep engaged, active, and strong directors and to attract replacements as they become necessary. Director performance in accord with best practices takes significantly more preparation (reading) time than it did historically. Off-meeting contacts among directors, regular participation in industry specific and governance training, use of periodic off-site planning "retreats," presentations from outside directors, and special reports from management providing a depth that normal quarterly reporting simply cannot typify the kinds of activities that require directors to spend more time than they used to keep abreast of a changing and complex business.

These conclusions do not intend criticism of the current board in the pursuit of how its mission may be defined and its expectations get communicated. Rather, the issue may be more one of: (a) redefining that mission along the lines of current best practices in a way that changes expectations, (b) identifying the need for added skills and experience, and (c) as importantly, recognizing that increased and broadened efforts require compensation approaches and levels designed to keep good directors and get new ones to agree to come aboard.

10.2. Hydro lacks a needed, single executive under which it can consolidate the principal functions associated with delivering utility service. *(Recommendation No. 10.2)*

The Nalcor CEO, who serves Hydro and other Nalcor lines of business in a similar capacity, has a breadth of responsibilities that permits him to spend only limited time managing Hydro day-to-day. Moreover, the other business lines for which he is responsible present fundamentally different operational challenges and risks and business opportunities. It is not unusual for administrative and general functions in a utility holding company structure to report to the utility holding company CEO (*i.e.*, above the level of the senior officer) who consolidates principal utility functions. It is unusual for the functions represented by the two Hydro vice presidents and overseen by the Nalcor executive in charge of Project Execution and Technical Services to come together first at the parent CEO level, particularly given the size and nature of Nalcor's other businesses.

A complicating factor arises from the need to address Hydro's future organization in the broad context that the addition of Muskrat Falls will create. Consideration is being (and should be) given to the large increase in hydro generation operations that this facility will bring. Optimizing the capability to become a material participant in wholesale power markets outside Newfoundland and Labrador also warrants careful attention, and likely presents a variety of organizational options. Other considerations like these may have significant influence on what functions and business operations remain in or get assigned to Hydro in the post-Muskrat Falls world.

Liberty's discussions with executive management indicated that Senior Hydro leadership plans to address, by the end of 2015, internal leadership needs along with the broader ones, many of which need to be in place by 2017, given the current Muskrat Falls schedule. Executive leadership has identified and is seeking to deal with opportunities, risks, and organizational needs overall, but, at present, has yet to identify a set of final alternatives. This status does not present concern about actions in time to meet 2017 needs, but it does complicate the question of how to address the consolidating Hydro senior officer.

Liberty's view is that this executive needs to be in place soon, and that finding a leader with proven, top level utility executive experience to fill it is essential. With the definition of what Hydro "will be" in terms of what operations will reside within it for the long term uncertain, it may be difficult to find and attract candidates for a position whose dimensions will remain unclear, per Hydro's schedule, for about another year or so. However, it would be disappointing for the position to remain unfilled for that long.

Liberty also has concern about the reporting source and level of the Hydro regulatory affairs function. Bringing an executive-level voice to Hydro's leadership table would provide significant benefit to the process of ensuring that regulatory requirements and expectations form a more central part in senior leadership's planning, overseeing, measuring, and taking responsive action to emergent issues and problems with implications for regulators and the stakeholders to regulatory processes. The benefits of doing so are broad, and have implications for matters concerning service reliability.

A related issue involves the "home" (in Hydro's case Finance) in which responsibility for regulatory affair resides. Liberty believes that best practice recognizes regulatory affairs as a distinct function. In Liberty's experience, companies that locate regulatory affairs under Finance tend to give it a focus on the more mechanical aspects of regulatory affairs, such as tariffs, cost-of-service studies, revenue requirements, and reporting. These aspects have central importance, but primarily in a tactical way. They do not necessarily encompass thinking about regulatory requirements and expectations from more strategic, policy, and direction-setting perspectives. Those perspectives can run parallel to, and potentially in some cases, partially in conflict with financial ones. Thus, providing a senior voice separate from the financial one creates, in our view, is the best approach.

10.3. The use of the Project Execution and Technical Services Group to provide common services benefits Hydro and is appropriately managed, but lacks transparency in certain respects. (*Recommendation No. 10.3*)

The Project Execution and Technical Services Group provides for common management of a number of project management, engineering, and other technical services that benefit Hydro and the other Nalcor business units. Earlier chapters of this report address the group and its services in detail. Here, Liberty sought to determine whether there exists any reason for concern that the provision of common services has disadvantaged Hydro in terms of securing access needed to provide proper installation and operation of facilities required to provide reliable service.

Liberty found that the group has made reasonable assignments of its resources to Nalcor "home bases" (basically a split between Hydro and non-Hydro, with the latter generally termed Nalcor) since a transfer of employees and the creation of new positions effective generally for the year 2011. These assignments are driven by expectations about where the majority of an employee's time is expected to be spent (*i.e.*, on which Nalcor entity's behalf). Many of the employees in the group perform exclusively or nearly so for a particular entity. A lot of the work of Project Execution and Technical Services employees is project based (*e.g.*, designing a new transmission line, managing the construction of a new distribution substation). Variability in work requirements associated with such tasks routinely calls for the assignment of teams that must have a variety of skills. Having a common organization to provide them tends to lower the number of total resources needed. For example, if Hydro needs to make use of two-thirds of the time of a certain specialist on an ongoing basis and another Nalcor entity needs one-third of the time, sharing services means a total of only one. Alternatively, Hydro might pay for one and get somewhat less than full value, while the other entity might use contracted services at a cost premium.

Liberty examined the time spent overall by Project Execution and Technical Services employees home based at Hydro and at Nalcor (*i.e.*, non-Hydro). The data examined indicates that employee time conforms reasonably well to home bases. Particularly for longer projects, one might see a Nalcor home-based resource spend a great deal of time for Hydro. What does not appear, however, are year-over-year instances where the same employee is spending very large blocks of time charging other than his or her home base entity. Moreover, group management prepares detailed plans for the use of its employees, meaning that assignments of time inside or outside one's home base do not appear to occur "by default." To the contrary, expected hours assignments follow fairly clearly and comprehensively identified project assignments carried out as part of annual work planning and adjusted as work requirements inevitably change during the course of the year.

The information Liberty reviewed supports an observation that the group uses a common resource as one would hope; *i.e.*, using a pool of experts having a variety of needed capabilities in a planned manner to optimize performance. The earlier chapters of this report make some observations about the match between work resources and performance (particularly in terms of work backlogs), but none of those concerns appeared to Liberty to have a connection with the structure or use of Project Execution and Technical Services. Moreover, the most likely largest source of diversion of resources from Hydro's needs is Muskrat Falls, which has internalized its resource needs.

Liberty did, however, observe some elements that make the group's use of resources less transparent than it could be. That transparency is important because it is typical for stakeholders and regulators to have concern for verifying that common service organizations do not: (a) leave the utility sector with insufficient resources, or (b) make the utility sector a "sink" for unproductive time costs. There are also valid regulatory and stakeholder interests in how costs are charged and allocated. Liberty did not examine questions associated with this third area of interest, which takes particular and different lines of inquiry from those we were charged with pursuing.

Another transparency issue arises from the relative newness of the approach, which has only been in use for a few years, and which probably made its first substantial cost "appearance" in the most recent Hydro rate filing. It has taken the group some time to stabilize resource requirements and match home basing with expected go-forward work. Resource additions made at or soon after formation of the approach were home based at Hydro, pending a more permanent basing decision. Liberty did observe fluctuation in home basing assignments in many of the group's functions year over year. These changes, while understandable when made transparent with that explanation, do otherwise call into question the impacts of the changed approach on Hydro costs relative to the value it receives.

Another element of the transparency question arises from the need to ensure that the priorities and action items that will drive reliability improvement work in the near term will be met by sufficient, but not excessive resources.

Liberty believes that the work planning approaches and methods and the reporting capabilities of the group have the ability to provide the transparency that Liberty thinks is important in establishing the credibility of common resource use and in permitting outside review of the appropriateness of resources available to and actually planned for use in support of Hydro's needs.

10.4. Hydro has made strong first steps in establishing and implementing enterprise risk management.

Effective use of enterprise risk management is not yet a notable industry strength. Liberty considers it important for the industry to move strongly forward in making best practice use of enterprise risk management, particularly as it concerns infrastructure and operations. Hydro's use of the Nalcor framework has produced a comprehensive process document, albeit in draft form. Nalcor has also created a position focused on making enterprise risk management an embedded element of the management of its businesses. A recent personnel addition brings operational experience to the risk management function, which Liberty believes is important in bringing an operational focus to enterprise risk management, which had its origins in and which many still tend to view as a largely financially related concern.

Driving ownership of risk management to and below the business unit level has been a good move to place "ownership" of risk in the best hands. Hydro appears to have accepted that ownership and has taken steps to create a comprehensive register of its risks and to identify means to mitigate them.

10.5. Even given the strength of efforts to date, it remains important to enhance the use of risk management to address Hydro infrastructure and operating risks. (*Recommendation No. 10.4*)

E. Recommendations

10.1. Make adjustments that will bring the Hydro board of director structure and operations more in line with the prevailing utility/holding company model. *(Conclusion No. 10.1)*

Hydro should ensure that the breadth and depth of combined skills and experience needed for the board corresponds to the needs, opportunities, and risks presented by Hydro's current operations and expected future ones. Hydro should, over time, expand the directors' range of skills and experience to correspond to these identified needs, opportunities, and risks. Hydro should place on its board one or two directors who do not serve on the boards of other Nalcor entities. Finding a director possessing very senior level power (preferably electric utility) industry experience should be a priority in augmenting the board's breadth of skills and experience.

Hydro should also develop a program designed to increase board understanding of and engagement in annual planning processes and more detailed reporting on and engagement with management on service quality, infrastructure condition, and operational performance.

Finding and keeping the additional skills and experience and incenting the increased level of director engagement contemplated by this recommendation will, in the long run, require compensation commensurate with what commercial entities of a similar size, scope, and complexity pay. The long run is the appropriate view to take in implementing this recommendation as drastic, wholesale change could prove more disruptive than beneficial. Changes in director reporting, activities, level of engagement, and other work determinants also tend to be best implemented in a gradual, rather than abrupt, one-time manner.

10.2. Restructure the senior-level executive organization to create a consolidating executive within Hydro, and escalate the regulatory affairs function to the level of officer, reporting to the Hydro consolidating executive. (*Conclusion No. 10.2*)

The most common model for the position Liberty recommends would be what Liberty has seen defined as the utility chief operating officer. That position, sometimes called the President of the utility subsidiary would report to the holding company's chief executive officer. Sometimes in such a structure, the parent chief executive nominally holds the same title at the utility. The key point, however, is that the chief operating officer position be recognized as the lead utility executive for day-to-day operations. This change would bring the two existing Hydro vice presidents under the new position. It could also lead to decisions to restructure the means by which project management support (offered under Nalcor's Vice President of Project Execution and Technical Services) is provided to Hydro. At the least, Liberty would anticipate that it would strengthen Hydro's executive team functional direction over resources from that Nalcor group, whose project management resources are essentially split between Hydro and other Nalcor operations already.

The change Liberty recommends would require addressing the current Hydro Chief Operating Officer position (which exists at a level below the Hydro vice presidential level). That position was occasioned by the need to provide a focused means for taking the many corrective actions required to address reliability issues in the short term, while not losing focus on the many other needs that must be met to sustain normal operations.
Liberty also envisions the creation of a regulatory affairs executive that would report to the dedicated Hydro consolidating chief executive. Should there be a delay past mid-2015 in creating the new consolidating executive within Hydro, this new regulatory position should in the interim report directly to the Nalcor CEO.

In the event that longer term organizational deliberation causes such a delay in creating the consolidating executive, we see merit in considering the introduction of a seasoned industry executive limited to a short-term role. For such a person, particularly one at a well-advanced career stage, long-term job definition would not be a concern. It would also provide a fresh set of eyes and ears, benefitted by extensive experience, on Hydro's approaches, methods, and processes related to meeting reliability challenges and action lists.

In summary, Liberty believes Hydro would benefit materially from a full-time consolidating officer at the Hydro level at this time. Liberty appreciates the value in considering the broad post-Muskrat Falls context and its implications for making a clear executive job definition uncertain at this time. Nevertheless, Liberty urges dispatch in getting in place an officer who brings together the functions central to the infrastructure and operations systems that deliver service to IIS customers.

10.3. Submit to the Board a comparison of Project Execution and Technical Services work assignments resulting from the work planning process with home base assignments. (*Conclusion No. 10.3*)

Doing so for the most recent historical period and for the coming year will enable a verification that home base assignments conform to work assignments. Given that addressing reliability initiatives, action plans, and recommendations will comprise a major source of work that will not repeat over the longer term, Hydro should include an identification of Project Execution and Technical Services work assignments that are associated with such non-recurring work.

It is also important for Hydro to exercise a system of strict controls for ensuring that charging for such work properly aligns cost causation with cost responsibility. Hydro should periodically make transparent its conclusions and level of confidence that Hydro bears costs strictly in proportion to its contribution to their causation. As noted, Liberty was not charged with undertaking an examination of this important matter. Liberty lists it here in order to make clear that our not otherwise addressing it should not be interpreted as a conclusion that it is not necessary or appropriate.

10.4. Enhance and finalize the draft master enterprise risk document and engage risk management personnel early and with operations personnel in identifying, sizing, and planning for mitigation of operations risks. (*Conclusion No. 10.5*)

The master document remains a draft. As a first step, finalizing it is necessary. That finalization process also needs to broaden its “messaging” as well. One of the factors that commonly limits full acceptance of enterprise risk management is its origins in financial and trading risk and the corresponding tendency for many to see it as largely confined to such issues. Nominally, the draft document addresses operational risk, but where it provides narrative descriptions of particular matters, it does so in financial terms or provides examples that are financial in nature. Incorporating more “real world” discussions of operating risk is therefore an important element of document finalization.

Liberty reviewed the register Hydro has prepared to identify and assess its operating risks. First, Liberty found that what looks at first like a long list of risks becomes much shorter when recognizing that many listings involve essentially the same risks, differentiated only by the nature of the consequence they can cause. Second, Liberty found that juxtaposing risks and their associated mitigation measures gives the impression the list of risks seemed to focus on ones already mitigated (*i.e.*, ones about which the author(s) felt comfortable already). Liberty’s concern is whether the list reflects more what gives operators real concern or more what they would like their superiors to feel comfortable that they have already been successful in addressing.

Liberty considers best practice as engaging risk professionals with risk owners as part of the process of identifying risk. Those trained in risk management as a process supported by a set of well-designed tools bring a more useful, open-ended way of thinking about what risks really are, and how combinations of unexpected circumstances create it. Liberty believes that bringing risk personnel to the table with operations personnel (risk “owners”) when risks are being blue-skied, identified, sized, and weighted is the best approach.

Appendix A: Conclusions and Recommendations Summary

Chapter II: Planning and Supply

Conclusions

2.1. **Hydro has made major improvements in its load forecasting capabilities as they apply to supply planning.** *(Recommendation No. 2.1 and 2.2)*

2.2. **Improvements to the short-term operating forecasts have also been made, but have not yet been fully proven.** *(Recommendation No. 2.1 and 2.2)*

2.3. **Hydro has made significant improvement in relating transmission losses to generation configurations, but has yet to complete the effort.** *(Recommendation No. 2.3)*

2.4. **Hydro has implemented the change to load reporting on an IIS basis, as recommended.**

2.5. **Liberty continues to consider the P90 forecast as the preferred planning base.** *(Recommendation Nos. 2.4 and 2.5)*

2.6. **Hydro's conclusion that weather caused actual peak load to exceed the forecasted annual peak forecasted in all four months of the 2013-14 winter warrants further support.** *(Recommendation No. 2.6)*

2.7. **Hydro's reconstruction of its peak loads to account for conditions that can make it artificially low is not convincing.** *(Recommendation No. 2.6)*

2.8. **Hydro implemented a number of load forecasting process improvements during 2014.**

2.9. **Despite nearly 200 MW of additional generation and demand-side resources, the supply situation is expected to remain tight until the arrival of Muskrat Falls.**

2.10. **Additional new generation does not present a good option, unless new load materializes or availability declines.**

2.11. **Despite improvement initiatives in 2014, availability remains a major challenge.**

2.12. **The new CT is urgently needed for this winter and must be expedited into service as quickly as possible. (***Recommendation No. 2.10)*

2.13. **Securing arrangements for 75 MW (including one for 15 MW in the process of finalization) in recent months reflects a successful effort to secure interruptible load.**

2.14. **Hydro's application of color coding is not fully meeting the Board's requirements in seeking reports, nor does that application serve to give Hydro management early warning of matters that may require its intervention.** *(Recommendation No. 2.11 and 2.12)*

2.15. **Maintenance initiatives during 2014 have been generally successful.** *(Recommendation Nos. 2.13 and 2.14)*

2.16. **Despite substantial progress in addressing winter readiness, lingering problems with Hydro's existing CTs pose supply adequacy threats this winter.** *(Recommendation Nos. 2.13 and 2.14)*

2.17. **Hydro has made progress in completing planned 2014 capital projects at its generating units.**

2.18. **While progress has been made in assessing parts criticality for generating units, Hydro has yet to complete the procurement of critical spares.** *(Recommendation No. 2.15)*

2.19. **Hydro has made reasonable progress in structuring and executing a winter readiness plan and should continue to develop its acceptance and use.**

2.20. **Liberty found field execution of the asset management program in 2014 to be sound, recognizing, however, that uncertainties about certain generating units remain.**

2.21. **Conservation and Demand Management Programs have focused on cost-effective energy reductions; the focus needs to expand to include demand reductions.** *(Recommendation 2.16)*

2.22. **History suggests that Hydro will consult with Newfoundland Power on the design and results of the coming analyses related to conservation and demand management, but it is not clear that Newfoundland Power will share "ownership" of the process.**

Recommendations

2.1. **Provide the Board with monthly updates on the status of Nostradamus upgrades until the production model is fully in-service and shaken down.** *(Conclusion No. 2.1 and 2.2)*

2.2. **By April 30, 2015, provide the Board an assessment of the effectiveness of Nostradamus during the 2014-15 winter and the sufficiency of the model for continued future use.** *(Conclusion No. 2.1 and 2.2)*

2.3. **Provide the Board with the guide on system losses under various configurations and any instructions for their use.** ***(Conclusion No. 2.3)***

2.4. **Continue to include the P90 load forecast prominently in all evaluations of power supply adequacy.** *(Conclusion No. 2.5)*

2.5. **By March 1, 2015, provide data relating the actual values of the weather variable on the 2013-14 winter days on which the annual peak forecast was exceeded.** *(Conclusion No. 2.5)*

2.6. **By March 1, 2015: (1) clarify Hydro's proposed reconstruction of the winter 2013-14 peak, (2) provide a specific value for the reconstructed peak, and (3) report on the impact of the reconstructed peak on the analysis of 2013-14 forecast exceedances.** *(Conclusion Nos. 2.6 and 2.7)*

2.7. **Validate a reasonable and practical criterion for reserve margins, although not necessarily in the form of a rigid number, and characterize the degree of risk associated with that criterion.**

2.8. Report quarterly on the rolling 12-month performance of its units, including actual forced outage rates and their relation to: (a) past historical rates, and (b) the assumptions used in the LOLH calculations.

2.9. Report promptly to the Board any potential change in the outlook for the adequacy of supply, including increases in forecasted peaks or reductions in unit availabilities.

2.10. Continue to treat completion of the new CT as soon as possible a high priority for Hydro management, supported by close executive attention. (*Conclusion No. 2.12)*

2.11. Establish and use a more effective system of reporting and analyzing status to give Hydro management early warning and the opportunity for intervention. *(Conclusion No. 2.14)*

2.12. In all reports to the Board, provide, and adhere to, a clear definition of reporting practices, including the definition of classifications (such as colors) used to categorize performance status. *(Conclusion No. 2.14)*

2.13. Given the vulnerabilities likely to be present on December 1, 2014, Hydro must take at least the following actions immediately:

- **a) Prepare an emergency contingency plan to identify all generation resources for a potential supply emergency while the new CT remains unavailable.**
- **b) Report to the Board all steps being taken to expedite completion of the new CT.**
- **c) Be prepared to trigger emergency plans when and if extreme weather sufficient to reach or exceed expected peaks is forecast.**
- **d) Report to the Board daily whenever forecasted reserves for the day are less than 10 percent.**
- **e) Report to the Board immediately whenever forecast reserves fall under 10 percent during any day.** *(Conclusion No. 2.15 and 2.16)*

2.14. Continue to rely on the old CTs for reliable capacity and continue to focus on steps to improve their availability. *(Conclusion No. 2.15 and 2.16)*

2.15. Report to the Board by February 15, 2015, the final status of the program for critical spares, its results versus expectations of the master plan, a listing of spares to be procured, and when they will be available. *(Conclusion No. 2.18)*

2.16. Complete planned demand management analysis on a Hydro/Newfoundland Power jointly scoped, conducted, and developed basis and report to the Board a structured cost/benefit analysis of short term program alternatives by September 15, 2015. *(Conclusion No. 2.21)*

Chapter III: Asset Management Programmatic Aspects

Conclusions

3.1. The design and scope of Hydro's asset management program is sound and conforms to best practices.

Recommendations

Recommendations relating to execution of asset management activities are set out in Chapters II and V.

Chapter IV: Transmission and Distribution System Planning and Design

Conclusions

4.1. Customers on the IIS experienced a greater number of lengthy interruptions because of planned transmission system maintenance than because of forced interruptions. *(Recommendation No. 4.1)*

4.2. Transmission-forced outage frequencies and durations both increased from 2009 to 2013.

4.3. Distribution outage frequencies and durations have increased, but remain consistent with Canadian averages after adjustment for major events.

4.4. Loss of supply and scheduled outages have been the largest contributors to outages.

4.5. Connectors, switches, and insulators made the largest contribution to equipment caused outages.

4.6. The lack of a focused worst-feeder program creates a gap in addressing reliability issues. *(Recommendation No. 4.2)*

4.7. Hydro does not compare cost with projected avoidance of customer interruption numbers or minutes in prioritizing distribution upgrade projects. *(Recommendation No. 4.3)*

4.8. Despite a structured process for prioritizing projects, it is not clear that Hydro sufficiently emphasizes SAIFI and SAIDI. *(Recommendation No. 4.4)*

4.9. Hydro plans its transmission and distribution systems for load growth and other technical constraints on an appropriate basis.

4.10. Hydro's distribution system planning criteria are also consistent with good utility practices.

4.11. Hydro's load flow, voltage, stability, interconnection, and short circuit studies are appropriate and consistent with good utility practices.

4.12. Hydro's Distribution Planning group provides those technical studies required to support the Transmission and Rural Operation staff.

4.13. Studies show that all transmission lines, terminal station transformers, substation transformers, and distribution feeders should operate within the limits of applicable equipment or N-1 transformer contingency ratings during the winter 2014/2015 peak demand.

4.14. Hydro reports that it has completed the transmission and distribution planning actions identified in its Integrated Action Plan.

4.15. Some of Hydro's 138 kV transmission circuits and nearly all of its 66/69 kV transmission circuits on the Island Interconnected System are radial, causing customer outages for forced and planned circuit outages.

4.16. Hydro has built its transmission lines and distribution feeders in excess of Canadian Standards Association (CSA) Overhead Systems criteria and in conformity with good utility practice.

4.17. Hydro uses IEEE Standard transmission and distribution conductor and transformer capacities for planning and operating its electric systems, which conforms to good utility practices.

4.18. Hydro allows limited temporary overloading of its transmission lines and its terminal station transformers, but limiting the "hot spot" temperature to 110°C appears to be unduly conservative.

4.19. Hydro has incorporated redundancy (N-1 contingency) in its transmission lines and terminal station buses consistent with the needs of the system. Rather than maintaining a spare 125 MVA transformer, it however depends on its N-1 transformer contingency designs to maintain system loads in case of a transformer failure. *(Recommendation No. 4.5)*

4.20. Hydro does not have SCADA monitoring or control on three 66 kV transmission circuits and fourteen of its fifty-two terminal stations; it has SCADA control for only ten of its thirty-five distribution substations. *(Recommendation No. 4.6)*

4.21. Practices for transmission system raptor protection, lightning protection, and galloping conductor prevention have conformed to good utility practices.

4.22. Few Hydro distribution substations have multiple transformers and only some of the feeders can be tied to other feeders, which typifies rural distribution systems in our experience.

4.23. Hydro's distribution lightning protection, its use of downstream reclosers, and its distribution power system studies were consistent with good utility practices. However Hydro does not install animal guards on its distribution substation or feeder equipment. (*Recommendation No. 4.7*)

4.24. Hydro is currently updating its transmission Geographic Information System (GIS) data. Currently, its GIS, which contains all data related to its assets for its transmission system is only about 65 percent up to date. It should continue with updating not only its transmission equipment data, but also its distribution equipment data.

4.25. Protection and Control staffing is appropriate.

4.26. Protective relay scheme designs conform to good utility practice.

4.27. Relay testing cycles conform to good utility practice and backlogs are reasonable.

4.28. Hydro uses an industry standard software package for conducting short circuit currents and relay coordination studies.

4.29. Protection and Controls personnel have appropriate involvement with investigations of relay scheme malfunctions.

4.30. Hydro has resumed replacement of obsolete electromechanical relays.

4.31. Hydro has reported progress in completing the 2014 Integrated Action Plan items involving protection and control; however, some have been delayed, as noted earlier in this chapter.

Recommendations

4.1. Investigate and report on methods that can reduce Planned T-SAIDI. *(Conclusion No. 4.1)*

4.2. Analyze and report on the benefits of a dedicated capital program component dedicated to addressing the previous year's 10 to 15 percent worst performing feeders. *(Conclusion No. 4.6)*

4.3. When prioritizing reliability projects, include a factor that relates cost to anticipated avoided customer interruption numbers and minutes. *(Conclusion No. 4.7)*

4.4. Increase the weighting given to resulting SAIFI, SAIDI, and numbers of customer interruptions and minutes when prioritizing proposed project. *(Conclusion No. 4.8)*

4.5. Perform a structured analysis of the costs and benefits of maintaining a spare for the 125 MVA transformers, considering age and equipment condition and the recent failures of the T1 transformer at Sunnyside Terminal Station and the T5 Transformer at Western Avalon Terminal Station. *(Conclusion No. 4.19)*

4.6. Conduct a structured analysis of expanding the SCADA system to include more and perhaps all distribution substations, in order to reduce customer minutes of interruption, and to reduce SAIDI. *(Conclusion No. 4.20)*

4.7. Apply animal guards at distribution substations when conducting maintenance work in the substations. *(Conclusion No. 4.23)*

Chapter V: TRO Asset Management

Conclusions

5.1. The advanced age of much of Hydro's T&D equipment will require substantial levels of maintenance and replacement.

5.2. Hydro conducts vegetation management consistent with good utility practice and the needs of the system.

5.3. Recent improvement in air blast circuit breaker maintenance has produced conformity with good utility practices. *(Recommendation No. 5.1)*

5.4. It is not clear that Hydro brings to bear sufficient numbers of skilled resources to prevent undue backlogs in maintenance work. *(Recommendation No. 5.1)*

5.5. **The radial configuration of the distribution and portions of the transmission (particularly 66 kV) systems leads Hydro to defer maintenance work to avoid required customer outages.** (*Recommendation No. 5.1*)

5.6. **Hydro does not make available to its field personnel the electronic equipment that has come into common use in the industry.** (*Recommendation No. 5.2*)

5.7. **Hydro's annual Wood Pole Line Management program reflects best utility practices.**

5.8. **Hydro has been appropriately funding its operations and maintenance work.**

5.9. **Hydro has been increasing its transmission and distribution capital investments.**

5.10. **As of the December 10, 2014 report, Hydro reported itself to be on track for completing the transmission and distribution actions listed in the Integrated Action Plan.**

Recommendations

5.1. **Formulate a comprehensive and structured plan to bring maintenance backlogs to a more appropriate sustained level.** *(Conclusions Nos. 5.3, 5.4 and 5.5)*

5.2. **Perform a cost/benefit analysis of providing crews with laptop computers.** (*Conclusion No. 5.6*)

Chapter VI: System Operations

Conclusions

6.1. **Hydro's Energy Control Center has an adequate number of experienced operators and trainees, as well as well-defined roles for support engineers.**

6.2. **Hydro's Energy Control Center is appropriately equipped with computer-based tools for operating its transmission system, including SCADA monitoring and control, Energy Management System energy and demand management.**

6.3. **Hydro shares real-time data, via a link between SCADA systems, with Newfoundland Power.**

6.4. **Hydro has not installed SCADA monitoring and control on a sufficient number of its distribution feeders.** *(See Recommendation No.3.6 in Chapter III)*

Recommendations

Liberty has no recommendations concerning system operations, but notes the related Recommendation No. 4.6.

Chapter VII: Outage Management

Conclusions

7.1. **The manual, paper-based outage management process does not conform with best utility practices.** *(Recommendation No. 7.1)*

7.2. The ability to detect customer outages following installation of automated meter reading should work with an Outage Management System.

7.3. Hydro has adequate protocols for communication with Newfoundland Power regarding planned transmission, generation, and terminal station equipment outages.

Recommendations

7.1. Study the costs and benefits of a variety of Outage Management System opportunities in order to provide a basis for assessing potential options. *(Conclusion No. 7.1)*

Chapter VIII: Emergency Management

Conclusions

8.1. The Nalcor/Hydro Emergency Operations Center location, contents, and the assigned staffing duties conform to good utility practices.

8.2. Hydro's Corporate Emergency Response Plan is generally sufficient, but does not give managers guidance in determining whether to classify an outage event as minor, major, or catastrophic. (*Recommendation No. 8.1*)

8.3. Hydro's Severe Weather Preparedness Protocol is generally sufficient, but does not fully address certain matters. (*Recommendation #8.1, 8.2, and 8.3*)

8.4. Hydro provides a number of Operating Instructions that address readiness for specific equipment-caused contingencies that may or may not be related to severe weather.

8.5. Hydro conducted 2014/2015 winter preparedness exercises, drills, and tests in recognition of lessons-learned from previous winters, and has enhanced and formalized communications with Newfoundland Power.

8.6. Hydro completed all of its emergency preparedness, communication, and coordination Integrated Action Plans Items.

Recommendations

8.1. Include in the Corporate Emergency Response Plan and in the Severe Weather Preparedness Protocol guidelines for determining how to classify a predicted or actual outage event as minor, major, or catastrophic in terms of numbers of customer interruptions or customer interruption hours, as a minor, major, or catastrophic emergency for determining preparedness requirements. *(Conclusion Nos.8.2 and 8.3)*

8.2. Develop a Restoration Protocol, in addition to the Severe Weather Preparedness Protocol, to address: (a) assessing storm damage, (b) assigning a Storm Level of activity based on the magnitude of equipment damage and customer outages, (c) providing emergency living quarters and meals for crews, when necessary, (d) protecting the public from downed lines, and (e) prioritizing restoration of terminal stations, substations, and feeders. *(Conclusion No. 8.3)*

8.3. **Include references in the Restoration Protocol to the uses of the various restoration-related Operating Instructions which may apply to Severe Weather related restorations.** *(Conclusion No. 8.3)*

Chapter IX: Customer Service and Outage Communications Issues

Conclusions

9.1. **Hydro has reported significant progress on the outage improvement recommendations, with remaining work on track for completion.**

9.2. **Hydro's largest customers are served and supported largely by the System Operations Department, not the Customer Service Department.** (*Recommendation No. 9.1*)

9.3. **Hydro's Customer Satisfaction Surveys have focused on residential and small commercial customers.** *(Recommendation No. 9.2)*

Recommendations

9.1. **Hydro should develop a key accounts management program to support and serve large industrial and commercial customers.** *(Conclusion No. 9.2)*

9.2. **Hydro should conduct customer research to better understand its largest customers.** *(Conclusion No. 9.3)*

Chapter X: Governance and Staffing

Conclusions

10.1. **After examining the Hydro board of directors in relation to the usual model for holding company structures, Liberty found a number of areas that can be changed to enhance its effectiveness.** (*Recommendation No. 10.1*)

10.2. **Hydro lacks a needed, single executive under which it can consolidate the principal functions associated with delivering utility service.** *(Recommendation No. 10.2*)

10.3. **The use of the Project Execution and Technical Services Group to provide common services benefits Hydro and is appropriately managed, but lacks transparency in certain respects.** (*Recommendation No. 10.3*)

10.4. **Hydro has made strong first steps in establishing and implementing enterprise risk management.**

10.5. **Even given the strength of efforts to date, it remains important to enhance the use of risk management to address Hydro infrastructure and operating risks.** (*Recommendation No. 10.4*)

Recommendations

10.1. **Make adjustments that will bring the Hydro board of director structure and operations more in line with the prevailing utility/holding company model.** *(Conclusion No. 10.1)*

10.2. **Restructure the senior-level executive organization to create a consolidating executive within Hydro, and escalate the regulatory affairs function to the level of officer, reporting to the Hydro consolidating executive.** (*Conclusion No. 10.2*)

10.3. **Submit to the Board a comparison of Project Execution and Technical Services work assignments resulting from the work planning process with home base assignments.** (*Conclusion No. 10.3*)

10.4. **Enhance and finalize the draft master enterprise risk document and engage risk management personnel early and with operations personnel in identifying, sizing, and planning for mitigation of operations risks.** (*Conclusion No. 10.5*)