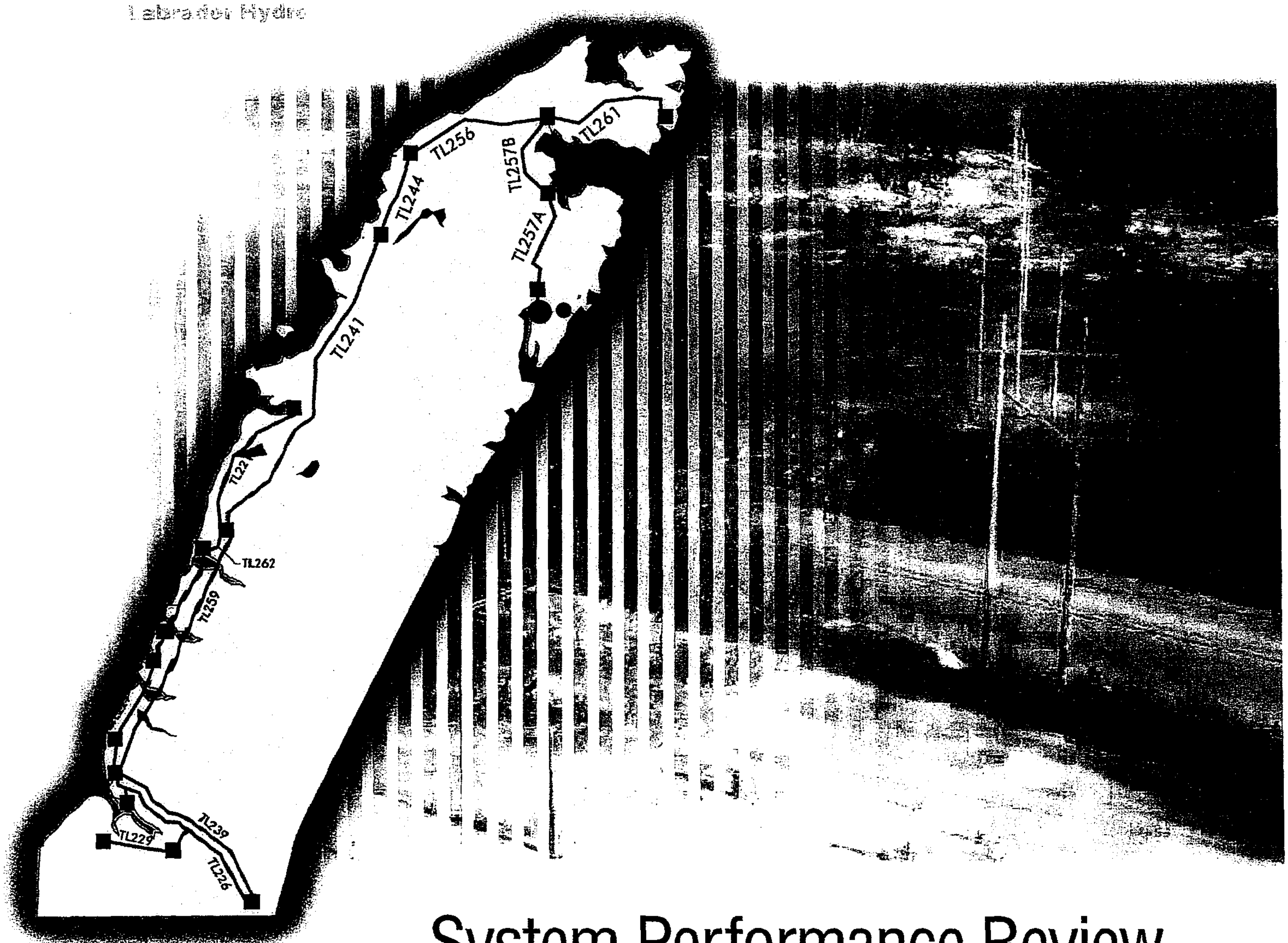
Q. Please provide any and all studies produced in response to P.U. 5 (2000-2001) in regards to the amount of emergency power which should be in place in the GNP.

A. Please see the attached report.

IC-231 NLH
Attachment

HYDRO

Newfoundland and
Labrador Hydro



System Performance Review
Great Northern Peninsula

June 2003

ACRES
International

Newfoundland and Labrador Hydro
Hydro Place, Columbus Drive, St. John's, NL A1B 4K7

System Performance Review
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P1482300

Acres International Limited
Oakville, Ontario

ACRES
International

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Appendixes

Executive Summary

This report provides documentation of a reliability performance review and analysis for the Great Northern Peninsula (GNP) transmission system owned and operated by Newfoundland & Labrador Hydro (Hydro), particularly serving the communities of Hawkes Bay and north. The report reviews the supply reliability performance at the customer level and identifies the primary and underlying causes of interruptions on the transmission system. The analysis has been extended to include an adequacy assessment of the standby generation, and its impact on the reliability statistics of six delivery points in the GNP north area. The report concludes with recommendations for improving transmission line performance and on the appropriate level and location of standby generation in the GNP north area.

The GNP system is a radial network extending a distance of approximately 400 km from the Deer Lake Terminal Station to the St. Anthony Terminal Station. The communities of St. Anthony, Main Brook and Roddickton are connected at the end of a long radial transmission system. Prior to 1996, these communities were isolated from the main transmission grid with their load being supplied by local generation; in particular, diesel generators at St. Anthony and a wood-fired thermal plant and diesel generators at Roddickton.

In 1999, Hydro applied to the Newfoundland Board of Commissioners of Public Utilities (the Board) to discontinue operation of its wood-fired thermal and diesel generation at Roddickton and consolidate all standby generation for the GNP system at St. Anthony. The Board conducted a public hearing into Hydro's application and authorized Hydro to abandon the woodchip fired thermal and diesel plant at Roddickton. However, Hydro was also advised to place 1500 – 2000 kW of emergency power at Roddickton, with any future discontinuance of this service to be authorized by the Board pursuant to an application by Hydro to be filed on or after July 1, 2003.

In delivering its ruling, the Board also issued the following directive:

> *"Hydro to conduct a study into the reliability of the transmission line serving the GNP and will identify the amount of emergency power required. The study to draw upon the information acquired by Hydro through the monitoring activities initiated pursuant to this order. The study will also identify the role of mobile, transportable, and fixed generation units and where these units should be placed, recognizing the history of reliability and the performance of the transmission lines. The study shall be conducted by an independent consultant and the report should be submitted to the board no later than July 1, 2003, reflecting the performance of the electrical system and its reliability up to May 31, 2003".*

Accordingly, Acres International, as an independent consultant to Hydro, has reviewed and analyzed six years of historical performance of the GNP system affecting Hawke's Bay and the area north of this community. Primarily, Acres used the system performance database developed and maintained by Hydro in carrying out the review and analysis of Transmission Equipment Forced Outage (TEFO) and Hydro Bulk Electric System (BES) delivery point performance statistics. In addition, the database information was augmented with outage reports provided separately in Excel spreadsheets for analyzing the underlying cause codes of delivery point interruptions.

Delivery Point and Transmission System Performance Review

A top down approach was used to analyze the delivery point and transmission line performance statistics. First at a high level, an overall reliability performance assessment was carried out for each delivery point by reviewing the SAIDI and SAIFI statistics and comparing them within Hydro and in comparison to other utilities. For this purpose, three-year rolling averages, yearly and five-year indices were evaluated and analyzed. Further, the primary and underlying causes of delivery point interruptions were analyzed in order to identify the core causes influencing the performance of the GNP system.

The review and analysis of six-year reliability performance of six delivery points in the GNP north area revealed that the SAIDI indices (average annual duration of interruptions) for each delivery point is in the typical acceptable range, as found in the electric supply industry.

The SAIFI-SI index (frequency of sustained interruptions) for all the delivery points has become acceptable in recent years. However, the SAIFI-MI indexes (frequency of momentary interruptions) as well as the composite SAIFI (SI+MI) indexes for momentary and sustained interruptions are higher than the range of values generally accepted in the utility industry.

The most prevalent primary cause for total customer interruption time was equipment related at 39.6% (major causes being Plum Point and Bear Cove stations, and TL221 & TL259 lines). The second most prevalent causes are adverse weather and system conditions with 30.4% (major causes being TL239, TL241 and TL221 lines) and 11.9 % respectively. Overall in the GNP North area, 53.1% of customer outage time was attributable to the transmission lines and other equipment related outage time was 46.9%.

The primary cause analysis on interruption frequency showed that the three 138 kV line sections TL241, TL239 and TL259 contributed to more than 66% of the total customer outage occurrences. Overall in the GNP North area, about 93% occurrences are transmission related and only 7% are attributable to other equipment and unknown causes.

The dominant underlying causes of interruptions were lightning on TL241, high winds on TL239, TL227 and TL221, and broken cross arm on TL259 due to storm conditions. Historically, adverse weather has been the major cause of interruptions on the GNP transmission system and is likely to remain the main cause of interruptions in future. The analysis of six-year data also revealed that most of the weather related interruptions occurred during 1998 and 1999, but the yearly interruption count has decreased in the last three years. This is partly attributable to the replacement of insulators on TL239, TL 226 and TL 227 circuits during 1999 and 2000.

The SAIDI values for the GNP North area compares favorably with overall Hydro statistics and these values are also quite low in comparison to the statistics of the other utilities used in the study and the CEA averages. However, the frequency of interruptions (SAIFI index values) in the GNP North area is the highest among the sample compared, as the delivery points in the GNP region are served by a significantly longer radial circuit among all compared.

Except TL259, all the other GNP area transmission circuits outperformed in terms of average annual interruption duration in comparison to the circuits belonging to other utilities and in comparison to the CEA average for similar types of circuits. The relatively poor statistics of TL259 are driven by an extreme event of about 7 hours outage due to a broken cross arm during storm conditions.

The sustainable delivery point performance in the GNP area is expected to be as follows:

- SAIDI $\leqslant$ 3.5 hr/year
- SAIFI – SI $\leqslant$ 6 occ/year
- SAIFI – MI $\leqslant$ 15 occ/year

Standby Generation Analysis

The standby generation at Hawkes Bay contributed merely 12% of the time in relation to the total unplanned outage time. This low contribution is chiefly attributable to unavailability of the units due to control problems within the plant or at the Hawkes Bay station. At the same time, the standby generation at St. Anthony reduced the total outage duration of this delivery point by more than 50%. The standby generation at Roddickton took a longer time to start, and its contribution to reduce the total outage time was only about 22%. This reduced contribution of Roddickton standby generation is attributable to the unavailability of the units, delayed local response time or delayed or no call from the control center asking for startup of these units.

If the standby generation were removed, the St. Anthony delivery point would experience the highest reliability impact, as the average duration of interruption would increase by more than 100%. Similarly, the reliability performance of Main Brook and Roddickton delivery points would deteriorate significantly with the removal of standby generation from Roddickton. However, as per the past experience with standby generation at

Hawkes Bay, the impact on delivery point reliability performance is not that significant. At the same time, it is worthwhile to mention that these reliability indices are well within the minimum performance standards followed in other parts of the country.

Based on the current load forecast and assuming that 25% of the load at each delivery point is essential load, it may be concluded that existing standby capacity should be sufficient and no additional generation will be required in the near future. If any additional generation were to be considered, portable generation would provide the greatest benefits.

In regard to the options considered for standby generation at Roddickton, the least cost and preferred solution is to move the two diesel units from Roddickton to St. Anthony.

Recommendations

The following is recommended in order to reduce the number of outages and sustained interruption times in future:

- Proactively maintain the protection and control equipment at stations serving the GNP North area to reduce sustained interruption times.
- Review the lightning statistics and identify locations on TL241 where shield wires or lightning arresters might be installed to reduce momentary interruptions on this long section of the 138 kV circuit.
- Identify the most exposed sections of circuits TL227, TL221 and TL239 to high winds, and implement corrective measures: for example, applying phase spacers or structure rebuilds to reduce the probability of phase slapping.

With respect to these recommendations, Hydro has been proactive some corrective actions had already been taken by the time this study was commissioned. Hydro is using its FALLS lightning analysis software to study lightning activity on the GNP and assist in the identification of performance improvement initiatives. Furthermore, in 1999 and 2000/01, TL 239 and TL 227 were partially re-insulated and structures modified in the most exposed areas to eliminate salt contamination and line slapping problems. These efforts should continue, so that the impact to customer outage statistics is further reduced.

Furthermore, in reviewing customer delivery point performance in relation to standby generation contribution, in particular the duration of interruptions in GNP north area, it is recommended that:

- The two diesel units be moved from Roddickton to St. Anthony, as it is a lowest capital cost solution, it provides better service to the customers at Roddickton, and it will have anticipated lower maintenance costs because of the close proximity of the maintenance crews.

1. Introduction

1 Introduction

Newfoundland and Labrador Hydro (Hydro) operates a 1500 MW isolated power system on the island of Newfoundland. The focus of this study is to review the performance of that part of the system that serves the Great Northern Peninsula (GNP), particularly the communities of Hawkes Bay and north.

The GNP system is the radial network extending a distance of approximately 400 km from the Deer Lake Terminal Station to the St. Anthony Terminal Station. Supply is provided by a long radial line that runs roughly along the western coastline of the island and is exposed to extreme weather conditions such as high winds, salt contamination and low temperatures. The system map shown in Figure 1.1 gives an overview of this radial line.

1.1 Background

The communities of Roddickton, St. Anthony and Main Brook are connected at the end of a long radial transmission system. Prior to 1996, these communities were isolated from the main transmission grid with their load being supplied by local generation; in particular, diesel generators at St. Anthony and a wood-fired thermal plant and diesel generators at Roddickton. In 1999, Hydro applied to the Newfoundland Board of Commissioners of Public Utilities (the Board) to discontinue operation of its wood-fired thermal and diesel generation at Roddickton and consolidate all standby generation for the GNP system at St. Anthony.

The Board conducted a public hearing into Hydro's application and issued orders on two different dates (February 18, 2000 and May 12, 2000), authorizing Hydro to abandon the woodchip fired thermal and diesel plant at Roddickton. However, Hydro was also advised to place an emergency power in the amount of 1500 – 2000 kW at Roddickton, in addition to the existing mini-hydro plant, with any future discontinuance of this service to be authorized by the Board pursuant to an application by Hydro to be filed on or after July 1, 2003. During the course of the hearing, questions were raised regarding the performance and reliability of the transmission system and the appropriate levels of standby generation in the GNP network. In delivering its ruling, the Board issued the following directive:

> *"Hydro to conduct a study into the reliability of the transmission line serving the GNP and will identify the amount of emergency power required. The study to draw upon the information acquired by Hydro through the monitoring activities initiated pursuant to this order. The study will also identify the role of mobile, transportable, and fixed generation units and where these units should be placed, recognizing the history of reliability and the performance of the transmission lines. The study shall be conducted by an independent consultant and the report*

should be submitted to the board no later than July 1, 2003, reflecting the performance of the electrical system and its reliability up to May 31, 2003".

Accordingly, Acres International, as an independent consultant to Hydro, has reviewed and analyzed six years of historical performance of the GNP system affecting Hawke's Bay and the area north of this community. Comparisons have been made with similar radial supply systems in other jurisdictions in North America. As a result, recommendations have been made for improving transmission line performance and on the appropriate level and location of standby generation in the region.

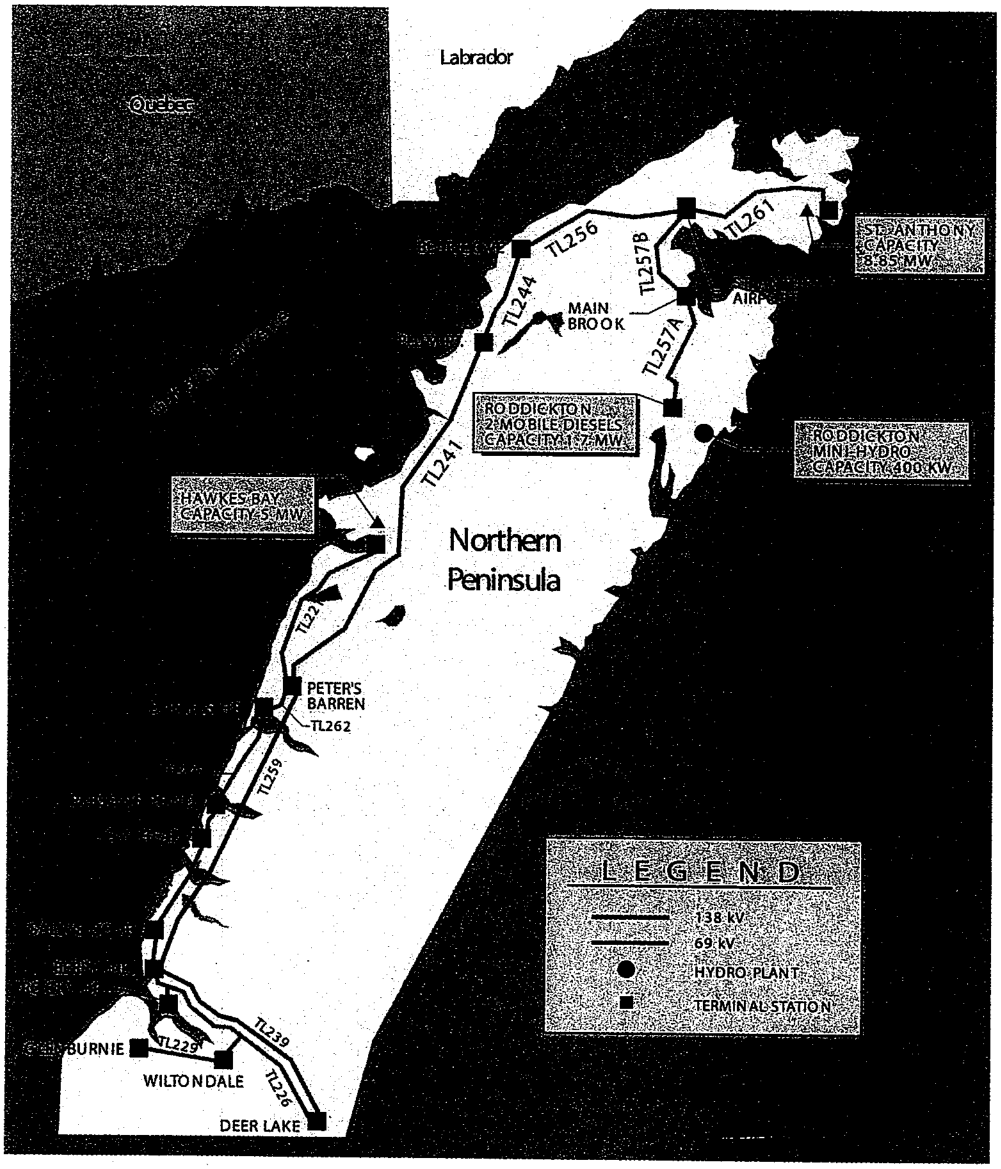


Figure 1.1 Transmission Grids and Generation – Northern Peninsula

1.2 Study Objective

The main objectives of this study are as follows.

Transmission System Performance Analysis

- Analyze the performance and reliability of the Hydro transmission system serving the Great Northern Peninsula, especially the system from Hawkes Bay and north.
- Identify any areas where specific feasible measures can be taken to improve the delivery point performance.
- Evaluate the performance of the GNP transmission system relative to other similar radial systems that Hydro operates in a similar climatic environment.
- Compare reliability statistics of the GNP transmission system with other utilities in North America and with CEA statistics.

Standby Generation Analysis

- Examine the current arrangement and placement of standby generation in the GNP network and make recommendations on the appropriate amount and location of standby generation.
- Evaluate the impact of standby generation on delivery point performance for: Hawkes Bay, Plum Point, Bear Cove, St. Anthony, Main Brook, and Roddickton.

2. Scope of Work and Methodology

2 Scope of Work and Methodology

The scope of work for the GNP system performance review study is comprised of two major tasks, which include: Transmission System Performance analysis and Standby Generation Analysis. The requirements under these study tasks were outlined in the original RFP issued on February 10, 2003 and in a subsequent release of February 21, 2003, titled *"GNP – Performance Study – Responses"*. Accordingly, the detailed scope and methodology adopted in respect of the two main tasks is described in the following sections.

It should be noted that definitions for some of the technical terms used in this report are included in Appendix A.

2.1 Data Collection and Review

On March 17 and 18, 2003, a kickoff meeting was held in Hydro office in St. John's, Newfoundland. The study framework was thoroughly reviewed with the Hydro staff and a detailed work plan was developed. The requirements for additional information on the subject were identified and issues related to data and assumptions were clarified. Accordingly, previous relevant studies and information was solicited and collected.

Correct and complete data availability is the most critical element in order to meet objectives of this study. Therefore, extensive and thorough effort has been made to collect and review the data. Acres started reviewing the collected data in terms of its completeness, data format, the connectivity logic for various data tables in the Access database, and data logging procedures as per industry standards. This data review included general inspection, engineering judgment, logic and relationship of different data elements in the database. After a detailed review, general observations regarding data are identified and discussed in Chapter 4 of this report.

Immediately after collecting the data during the project initiation meeting and subsequent data submissions by Hydro, Acres commenced the analytical work associated with the first main task of Transmission System Performance Analysis. Primarily, the Access database developed and maintained by Hydro has been used in carrying out the review and analysis of Transmission Equipment Forced Outage (TEFO) and Hydro Bulk Electric System (BES) delivery point performance statistics. The database was enhanced by improving the connectivity among different data items for better analytical capability and detailed analysis of the GNP system performance. In addition, the database information was augmented with the outage reports (provided separately in Excel spreadsheets) for analyzing the underlying cause codes of delivery point interruptions.

A complete list of data resources used in the analysis is given in Chapter 4 of this report. The commentary under each type of analysis mentioned below summarizes the methodology for GNP transmission system performance analysis.

2.2 Transmission System Performance Analysis

2.2.1 Review of GNP System Reliability Performance

All investigations were made based on the following:

- The historical reliability performance of the GNP system, as extracted from the Hydro outage reporting database,
- An analysis of the current transmission reliability conditions in the system, given recent investment and maintenance initiatives and observed trends in overall reliability and underlying interruption causes.

In order to assess the historical performance of the GNP transmission network, three-year rolling averages of delivery point performance indices have been analyzed, including June 1997 to May 2000, June 1998 to May 2001, June 1999 to May 2002, and June 2000 to May 2003.

The reliability performance, in terms of frequency and duration of interruptions at these delivery points, has also been analyzed on a yearly basis. The objective was to identify any specific years that were significant contributors to the reliability statistics and thus required additional analysis or investigation. Further, the primary and underlying causes of delivery point interruptions have been summarized in order to identify and assess the core causes influencing the performance of the GNP system.

2.2.2 Comparison of GNP System Reliability Performance with Other Systems

The GNP transmission network performance and delivery point statistics have been compared with:

- Similar radial systems on Hydro's transmission grid; the specific areas for comparison on the Hydro system are the southwest coast served by TL 214/215 and the Connaigre Peninsula served by TL 220.
- Similar radial systems of other utilities in cold maritime climates and/or similar environments that could be compared to the GNP system. Acres consulted the following utilities that have identified comparable radial supply systems. The data gathered from these utilities was used for comparison.

a) Nova Scotia Power, Canada
b) Bangor Hydro, USA
c) Hydro One, Ontario, Canada
d) Aquila Networks, British Columbia, Canada

- Overall performance of Hydro's system.
- Overall Canadian Electrical Association performance statistics.

2.2.3 Influence of Past Investment(s) and Maintenance Initiatives

The focus of the analysis was to capture the trends in overall performance of the GNP network, and on the trends within the underlying cause codes for the interruptions. The observed trends have been correlated with new investment and maintenance initiatives undertaken by Hydro during the period of the reported reliability statistics.

Evaluations of various transmission system investment and maintenance programming initiatives were also carried out to assess practical impacts on the historical results, which were extrapolated to the expected future system performance.

2.2.4 Feasible Actions to Improve the Delivery Point Reliability Performance

From the review of the historical reliability performance of the GNP system, the dominant interruption causes have been identified. These underlying causes led directly to identification of specific remedies that address the remaining reliability issues. Accordingly, recommendations have been made for any areas on the GNP system where specific feasible action could be taken to improve the delivery point performance and reliability.

2.3 Standby Generation Analysis

Evaluation of the impacts of the existing generation on reliability, and the impacts of removal of the generation on future reliability, has been assessed based on the historical data and the practical impacts of the standby generation in delivering these historical results. Accordingly, the justifications for any standby generation have been evaluated in the context of associated reliability improvements in the interruption frequency and duration. The methodology adopted in each of these evaluations is discussed in the following sections.

2.3.1 Review of Existing Standby Generation on Reliability Performance

The purpose of the performance review of the existing standby generation on the GNP was to appraise the impact on the supply system reliability of delivery points Hawkes Bay and north. The following work has been performed under this activity:

- Reviewed the current arrangement and location of standby generation on the GNP. Primarily, the standby generation at Hawkes Bay, Roddickton, and St. Anthony has been analyzed.

- Assessed the impact that this standby generation has had on the current supply system performance and appraised the overall reliability performance of that area from Hawkes Bay and north. The analysis has addressed the practical impacts both on the frequency and duration of interruptions in this area.

2.3.2 Reliability Performance without Standby Generation

The effect on the reliability performance of six delivery points has been evaluated for the situation if the generation were removed from Hawkes Bay, St. Anthony and Roddickton diesel plants. Predictive reliability assessment of the BES system, coupled with the historical reliability performance in the area, has been used in completing this analysis.

2.3.3 Justification and Assessment of Standby Generation Requirement

Following the analyses conducted in Sections 2.3.2 and 2.3.3, the practical impacts of any rearrangement or additions in the standby generation at Hawkes Bay and north have been examined. The justification for any standby generation has been evaluated in the context of associated reliability performance improvements in the six delivery points and relative to other utility practices elsewhere.

2.3.4 Portable versus Fixed Standby Generation

The role of portable versus fixed standby generation has been analyzed relative to maintaining or improving performance levels. The significant difference between portable and stationary generation stems from the possible inadequacy of the available generation and the longer lag times for full or partial supply restoration. These impacts have been explicitly analyzed, using the models developed for the previous analyses.

2.3.5 Options Considered and Associated Costs

These study results have been used in the evaluation of the justification for each investment initiative considered. Accordingly, the costs have been estimated to implement the recommendations made in this report.

3. Assumptions and Criteria

3 Assumptions and Criteria

3.1 Assumptions

The GNP transmission system performance analysis is based on the following assumptions:

1. The GNP area of the Hydro interconnected transmission system is operated in a radial fashion.

2. The generators at Hawkes Bay and St. Anthony are operated as standby generation during unplanned outages.

3. The generators at Roddickton are operated as emergency generation.

4. The generation at Hawkes Bay and St. Anthony can be used as system support, but such an evaluation is beyond the scope of this report.

3.2 Delivery Point Performance Criteria

Each year, Hydro management generally establishes the reliability targets for delivery point performance. The reliability statistics are then compared with the countrywide reliability statistics that are compiled by Canadian Electricity Association (CEA). The areas that contribute to poor performances are identified and accordingly, maintenance and capital work is initiated to improve future system performance. Hydro also takes preemptive actions where necessary to enhance delivery point service continuity and overall system reliability.

As part of Acres' investigation of transmission circuits operating under similar circumstances elsewhere, Acres also sought out customer delivery point performance standards used by other utility industry leaders which could be used for analysis of performance of the Hydro system and the GNP system. A good example is the performance standard recently developed by Hydro One Networks Inc. (Networks), which defines acceptable performance at the customer delivery point level, consistent with system wide standards. A summary is included in Appendix B. This standard reflects:

- Typical transmission-system configurations that take into account the historical development of the transmission system at the customer delivery point level;

- Historical performance at the customer delivery point level;

- Acceptable bands of performance at the customer delivery point level for the transmission system configurations; geographic area, load, and capacity levels; and
- Defined triggers that would initiate technical and financial evaluations by the transmitter and its customers regarding performance at the customer delivery point level, exemptions from such standards, and study triggers and results.

The Customer Delivery Point Performance Standards and Triggers that are proposed for Networks' transmission system are shown in Table 3.1 below. These delivery point performance standards are based on rigorous statistical analysis of the historical (1991-2000) performance as measured by the frequency and duration of outages that covers the impact of all momentary and sustained interruptions caused by forced outages, excluding force majeure events that are deemed appropriate to be excluded (e.g. 1998 Ice Storm, tornadoes, earthquakes, other acts of God and any other significant event having "excessive" impact on performance that is beyond the reasonable control of, and not a result of the fault or negligence of Networks).

Table 3.1: Networks' Delivery Point (DP) Performance Standards

Performance Measure	Delivery Point Performance Standards (Based on a Delivery Point's Total Average Station Load)							
	0-15 MW		15-40 MW		40-80 MW		>80 MW	
	Standard (Average Performance)	Minimum Standard of Performance	Standard (Average Performance)	Minimum Standard of Performance	Standard (Average Performance)	Minimum Standard of Performance	Standard (Average Performance)	Minimum Standard of Performance
DP Frequency of Interruptions (Outages/yr)	4.1	**9.0**	1.1	**3.5**	0.5	**1.5**	0.3	**1.0**
DP Interruption Duration (min/yr)	89	**360**	22	**140**	11	**55**	5	**25**

The minimum standards of performance are to be used as triggers by Networks to initiate technical and financial evaluations with affected customers to begin the process of addressing below standard performance. When the three year rolling average of delivery point performance falls below the minimum standard of performance or when delivery point customer(s) indicate that analysis is required, Networks will initiate technical and financial evaluations to assess remedies for improving reliability.

These bands are to:

- Accommodate normal year-to-year delivery point performance variations,
- Limit the number of delivery points that are to be considered "outliers" to a manageable/affordable level,
- Deliver a level of reliability that is commensurate with customer value,
- Direct/focus efforts for reliability improvements at the "worst" performing delivery points.

The proposed minimum performance standards correspond to a performance bandwidth designed to capture about 90% of all delivery point performance and leave about 10% of the delivery points to be classified as performance "outliers."

The objective of presenting the above criteria here is not to compare the performance of delivery points in the GNP system with delivery points in the Hydro One system; however, it provides a good yardstick for appraising the performance of the six delivery points in the GNP North area that have less than 15 MW average demands. Accordingly, the reliability performance statistics of six delivery points in the GNP North area may be weighed against the minimum standard performance requirements for frequency and duration of interruptions as depicted in Table 3.1.

4. Data Collection and Review

4 Data Collection and Review

4.1 Data Collection

The following information has been collected from Hydro for review and analysis:

1) Summary – Correspondence Related to the Application to the Board

2) Summary - Information provided to Board of Commissioners by Hydro

3) Summary - Transcripts of Board Hearings and Ruling

4) Hydro Bulk Electric System (BES) and Transmission Equipment Forced outage (TEFO) performance information, including frequency and duration of outages and underlying interruption causes – an Access database file. The Hydro Access database has been extensively used to extract performance indices related to transmission system outage data and delivery point interruptions. These indices formed the basis for evaluating the reliability performance of the GNP system.

5) BES 2001 Performance and Equipment review (complements #9)

6) Transmission line data servicing the GNP

7) Actual Demand and Load Forecast Chart for the GNP system, including the load duration curves for the GNP and St. Anthony area, the number of rural customers connected to the GNP system, and to the entire Hydro system

8) GNP Single Line Diagram Showing sample Power Flows and Voltages

9) BES Voltage classifications

10) Hydro Internal Report "TL214 Condition Assessment and Recommendations for Upgrading", September 9, 2002

11) Hydro Internal Report "Reliability Study of Transmission Lines in the Avalon and Connaigre Peninsulas", April 1996

12) A list of investment and maintenance programs executed within the GNP system over the study period

13) Design Transmittals and Justification Statements for the investment and maintenance projects on lines TL239, TL226, TL229, and TL262.

14) The excerpts of 'Performance Indices' and 'Damage Claims' sections from the Quarterly Regulatory Reports for the period from June 1999 to December 2002.

15) Operation and Maintenance (O/M) information on cost for operation of the Roddickton diesel generating plant

16) Diesel generation dispatch information

17) Long term generation rating information

18) Delivery point service continuity information

19) Lightning Strike information from 1998 to 2003

20) CEA 5-year TEFO Information

21) TEFO Underlying Cause Code information (6 years hand written notes)

22) System Single Line Diagram Reference A0-300E-36 Rev 53

4.2 BES and Delivery Point Information

Relevant information was extracted from the MS Access database, using various reports. The most common report summarizes occurrences and durations, including:

- Number of momentary and sustained outages
- Minutes of BES and customer outage time

This information was collected by delivery point and summarized on a regional level. Parameters of the report include:

- All unplanned outages only
- All momentary and sustained outages
- Timeframe: June 1st 1997, to May 31st 2003

The results presented in the following chapters of the report represent information up to and including December 31st, 2002 for TEFO information and up to and including March 31st for Delivery Point (DELPNT) information. A new data set was received June 4th, with the remaining data for TEFO and DELPNT, up to and including May 31st, 2003. An extraction of the data for Tables 5.2 to 5.7, upon which the analysis and conclusions are based, showed a variance in the percentages of less than 0.2% in almost every case, and no change occurred in the general order of highest to lowest in all tables.

4.3 Data Extraction from the Access Database

The information is collected in MS Access database based on several criteria. Not all events affecting the transmission system are "TEFO reportable". Consequently, there are occurrences of delivery point outages without an entry in the TEFO database identifying the root cause. An example would be distribution equipment failure at Plum Point (root cause), that had the secondary effect of tripping TL241. This in turn would cause at least one outage to all points north of Plum Point, if they were connected to the BES.

Acres developed a process to link several databases together based on date/time and human judgment. Accordingly, the results presented in this report maximize the available data, and are thus representative of actual historical reliability performance in spite of a small percentage of data not included.

4.4 Data Assimilation for Standby Generation Analysis

A summary of all delivery point interruptions was extracted from the MS Access database. Only records affecting the GNP North Area were retained. These were then sorted by delivery point and their outage duration. Information presented includes:

- Duration of BES outage in minutes
- Duration of outage in minutes as seen by the customers (Delivery Point)
- Impact of standby generation in minutes (difference between BES and DP numbers, where DP is less than BES).

In the case of modeling supply conditions without generation, yearly results were reviewed and the reliability of each delivery point was predicted. Since the grid is primarily radial from Hawkes Bay north, BES outage times (minutes) were compared to delivery point outage minutes. The following observations were made:

- More northerly DP's should have the same or greater BES outage times as compared to more southerly points along the same radial transmission line. In this analysis, St. Anthony, Main Brook and Roddickton were considered more north than Bear Cove.
- Any difference between actual DP performance (minutes) and modified BES performance is a strong indication of generator contribution in the improvement of delivery point outage time.

5. Transmission System Reliability Performance Review and Analysis

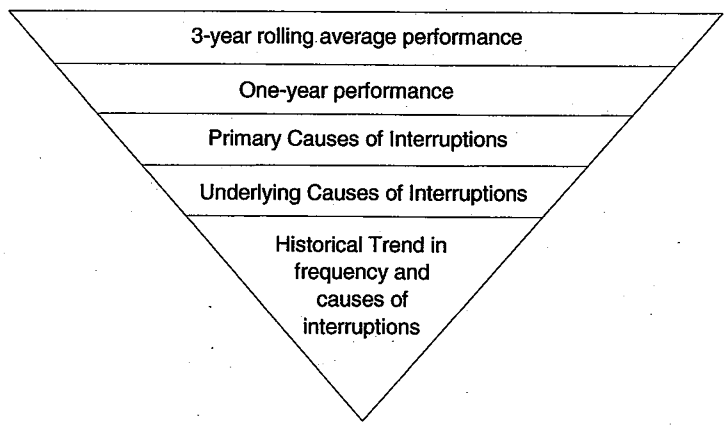
5 Transmission System Reliability Performance Review and Analysis

This chapter presents the results of historical reliability performance review of the Hydro interconnected transmission network that serves customers at six delivery points in the GNP system, namely GNP North area. These delivery points are Hawke's Bay, Plum Point, Bear Cove, St. Anthony, Main Brook and Roddickton. Table 5.1 shows the five year average number of customers for each delivery point in GNP North area.

Table 5.1: Customers in GNP North Area

Delivery Point Code	Delivery Point Name	Customers
HBY	Hawkes Bay	1,294
PPT	Plum Point	984
BCV	Bear Cove	935
SDP	St. Anthony	2,291
MBK	Main Brook	250
RWC	Roddickton	934
	Total	6,688

This chapter also presents the results of transmission network performance review in terms of primary and underlying causes of delivery point interruptions. The overall analysis has been performed as per layout of an inverted triangle as shown below:



At each stage of analysis, the corresponding strip in the above triangle has been highlighted for better readability and understanding.

5.1 Historical Reliability Performance Review

5.1.1 3 year Rolling Average Performance

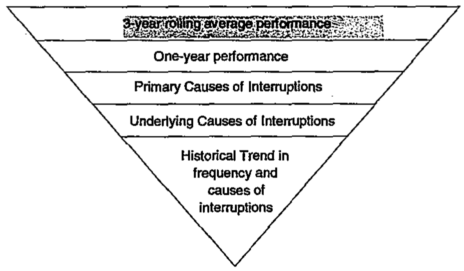
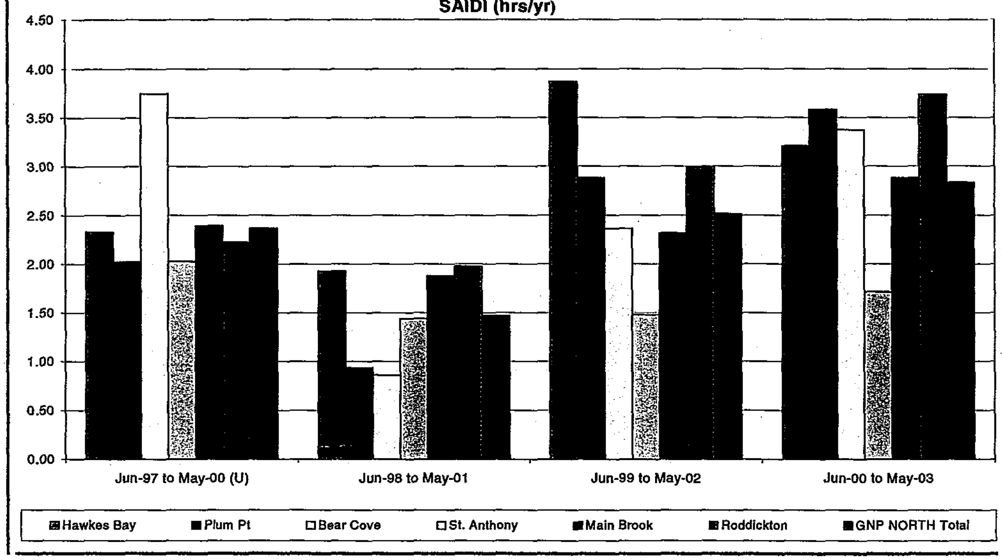


Figure 5.1 shows the three-year rolling average of System Average Interruption Duration Index (SAIDI) for six delivery points from Hawke's Bay north. These SAIDI indices represent the average annual duration of interruptions experienced by customers in the target area. The indices are based on the actual customer interruption durations after taking into account the standby generation contribution towards SAIDI.

Figure 5.1 shows a declining trend in the average annual duration of interruption for the 2nd period, but the SAIDI values increased during the 3rd and 4th 3-year periods.. Consequently, the 3-year rolling average SAIDI value for GNP North area is 2.79 hours/year, which is quite reasonable for a long radial supply system augmented by small contributions from the standby generation. Furthermore, it is well within the range of acceptable performance established in other jurisdictions for load levels similar to the GNP system, as exemplified by the standards adopted by Hydro One and presented in Table 3.1.

Figure 5.1 - Customer Delivery Point Performance
SAIDI (hrs/yr)



It is pertinent to point out that SAIDI values vary quite significantly between the delivery points supplied by the same radial circuit. This is principally due to the use of standby diesel generation at St. Anthony and Roddickton. Being at the tail end of a radial circuit, the SAIDI values for St. Anthony, Main Brook and Roddickton delivery points would normally be expected to be higher than those for Plum Point and Bear Cove, but due to the impact of the standby diesel generation, the SAIDI values at the three remote-end communities are somewhat lower.

Figures 5.2 give an overview of System Average Interruption Frequency Index for Sustained Interruptions (SAIFI-SI) in respect of six delivery points in the GNP North area. Similarly, Figure 5.3 shows SAIFI-MI index for Momentary Interruptions. These indices represent 3 year rolling average performance of the delivery points at the customer level.

Figure 5.2 - Customer Delivery Point Performance
SAIFI-SI (int/yr)

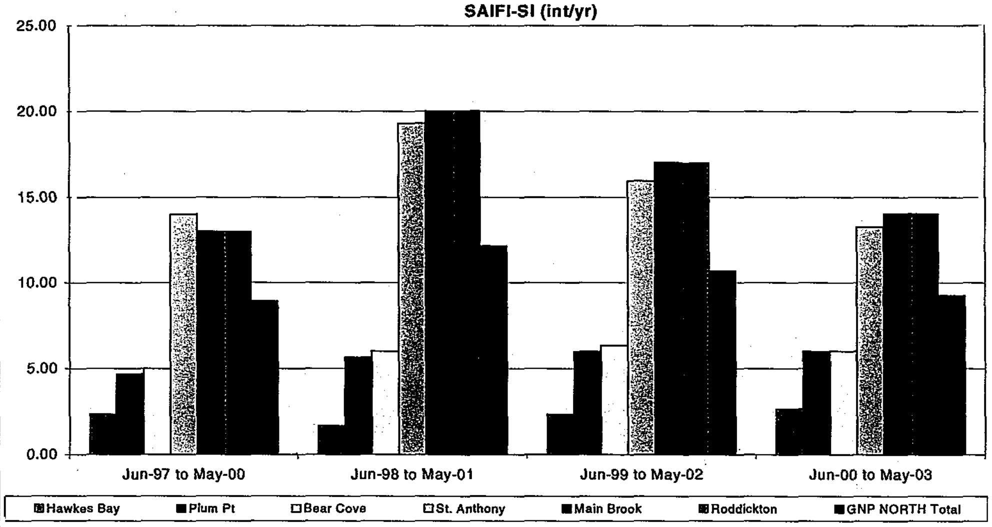


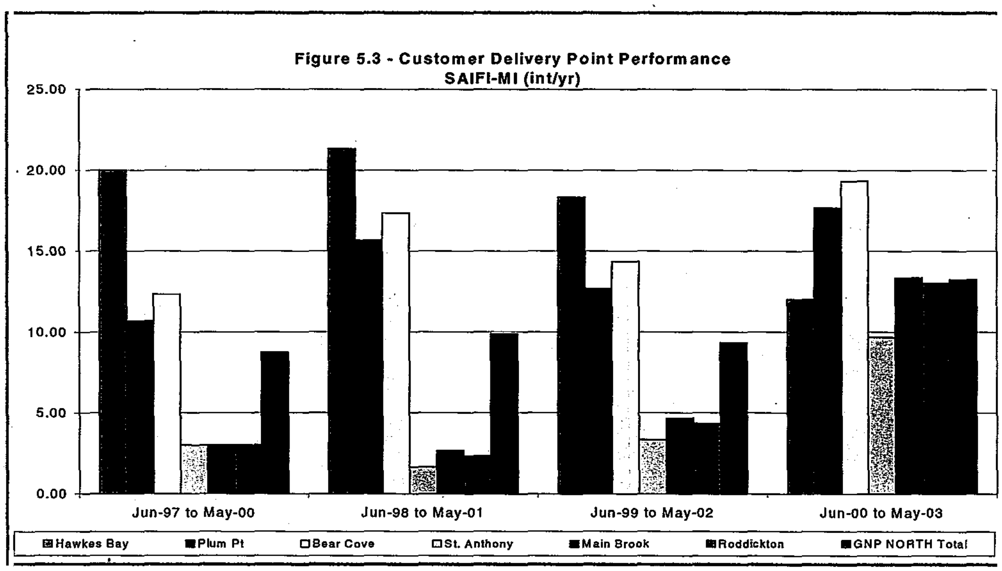
Figure 5.2 reflects a generally decreasing trend in the delivery point frequency of interruptions for sustained outages. However, the frequency of sustained interruptions corresponding to the St. Anthony, Main Brook and Roddickton delivery points are quite high in comparison to Plum Point and Bear Cove frequency indices. The results appear to be logical, as it is expected that the delivery points connected near the tail end of a radial supply would be subjected to a higher frequency of interruptions due to their greater exposure.

However, the detailed analysis indicate that the sustained interruptions for the three delivery points north of Bear Cove were logged as momentary interruptions for Plum Point and Bear Cove delivery points. This apparent inconsistency was mainly due to the practice of manual closing of TL256 at Bear Cove for the transmission circuits north of

Bear Cove prior to July 2001. Hence, the average interruption frequency values for sustained interruptions (SAIFI-SI), with respect to St. Anthony, Main Brook and Roddickton delivery points, could be misleading prior to July 2001. The SAIFI-SI indices based on the yearly data further highlights the impact of this operation limitation in the following section.

When the GNP interconnection was first put in service in the fall of 1996, the mode of operation for fault situations was to reconnect the system in two blocks. The TL 256 protection at Bear Cove was set to trip TL 256 on 'loss of supply'. Once the supply was restored at Bear Cove, TL 256 was closed manually. For faults on TL 256, auto-reclosing was always enabled. In July 2001, Hydro decided to reclose TL 256 automatically after 20 seconds if the Bear Cove bus voltage is restored.

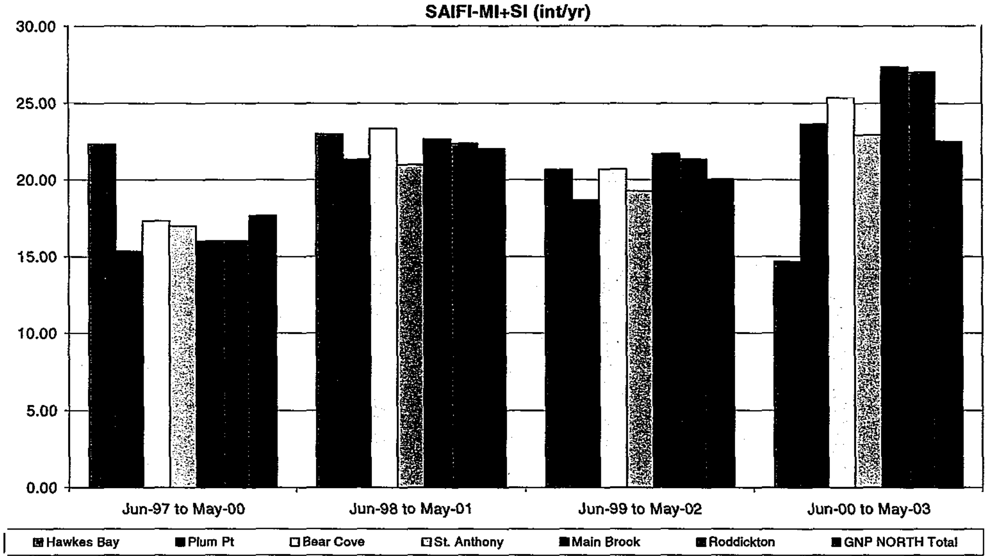
The 3-year rolling average values for SAIFI-MI index, as shown in Figure 5.3, show a declining trend for Hawkes Bay and an increasing trend for Plum Point and Bear Cove delivery points. Also, the SAIFI-MI index values for these delivery points are high for all the periods. In contrast, the SAIFI-MI indices for the other three delivery points are quite low during the 2nd and 3rd periods but rose fairly high during the last period.



With reference to one another, the individual delivery point SAIFI-MI results are not in the expected ranges. The St. Anthony, Main Brook and Roddickton delivery points would normally experience more interruptions in comparison to Plum Point and Bear Cove due to their remote end location in the radial supply system. However, the results are contrary to this expectation. As mentioned above, due to the manual closing operations north of Bear Cove, the momentary interruptions logged at Plum Point and Bear Cove were logged as sustained outages for the other three delivery points.

In order to assess the overall trend in frequency of interruptions in the GNP North area, the average interruption frequency values for sustained and momentary interruptions (SAIFI-SI+MI) are shown in Figure 5.4. For the periods analyzed, the results of collective interruption frequency indexes for all delivery points exceed the typical frequency (occurrences per year) generally reported for other utilities in the electric supply industry. For instance, Hydro One has a minimum performance standard of 9 occurrences per year as specified in Table 3.1.

Figure 5.4 - Customer Delivery Point Performance
SAIFI-MI+SI (int/yr)

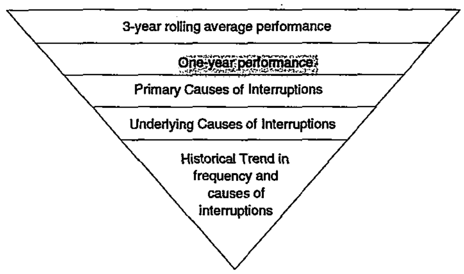


The 3-year rolling average for collective frequency index show to some extent an increasing trend through out the successive periods.

In summary, the SAIDI index for GNP North area show that the average annual duration of interruptions is in the acceptable range, which further implies that the integrated radial network supply to the GNP region is being adequately maintained by Hydro. The SAIFI-SI index for sustained interruptions also became acceptable for St. Anthony, Main Brook and Roddickton delivery points, as momentary interruptions began to be logged as momentary rather than sustained interruptions in the last two years. However, the SAIFI-MI indexes for momentary interruptions as well as the composite SAIFI (SI+MI) indexes for momentary and sustained interruptions are higher than the range of values generally acceptable in the utility industry.

As a general statement, it is safe to say that while the frequency of outages on the GNP appears to be constant, the composition is changing. More outages are of a momentary nature, with fewer being sustained.

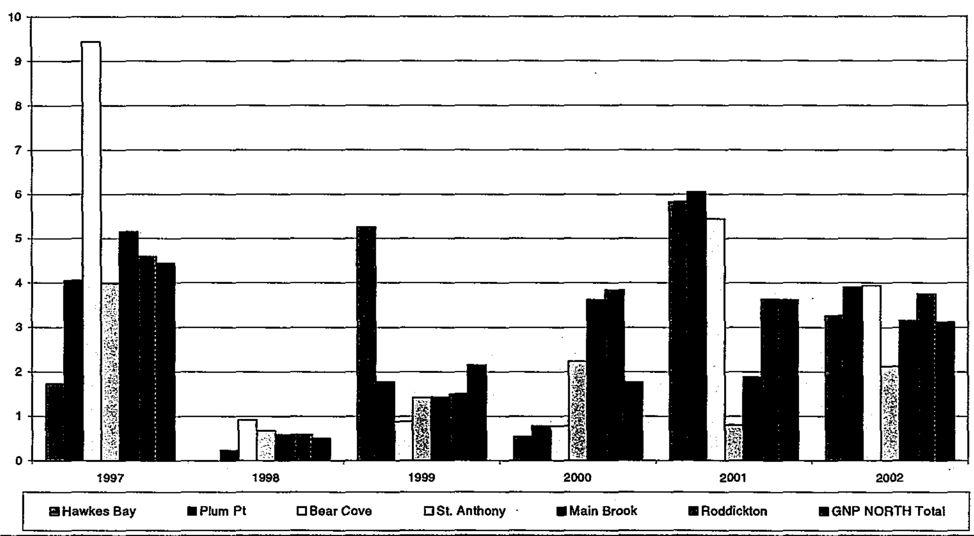
5.1.2 Yearly Performance



The date convention used in the following figures associates the time period of June 1st, 1997 to May 31st 1998 with the year 1997. Likewise, the data identified as 2002 represents the time period of June 1st, 2002 to May 31st, 2003.

Figure 5.5 shows a yearly variation in SAIDI indices for the customers of the aforementioned six delivery points in the Northern GNP area. With the exception of Bear Cove in 1997 and Hawkes Bay and Plum Point in 2001, the customer SAIDI values for each delivery point as well as for the overall GNP North area are within the reasonable practical range found in the utility industry. As discussed above, the increased trend during 2002 – 2003 period may be attributed to an outage of TL259 138-kV circuit due to a broken cross arm at a structure. Being a section in the radial supply chain, the outage of this element caused interruptions to all the other delivery points in the GNP North area.

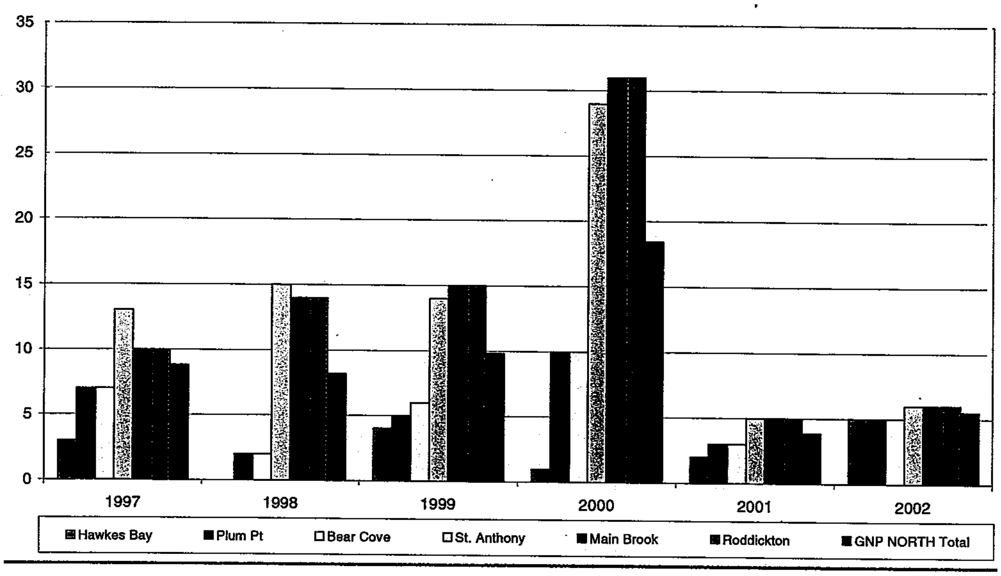
Figure 5.5 - Customer Delivery Point Performance SAIDI (hrs/yr)



In 2001, the SAIDI index values for Hawkes Bay, Plum Point and Bear Cove are high relative to the other delivery points. The SAIDI values for these three communities are also relatively high as compared to the SAIDI values for customers at the other three delivery points. This is primarily due to the standby generation contribution to the SAIDI statistics for customers served by St. Anthony, Main Brook and Roddickton delivery points.

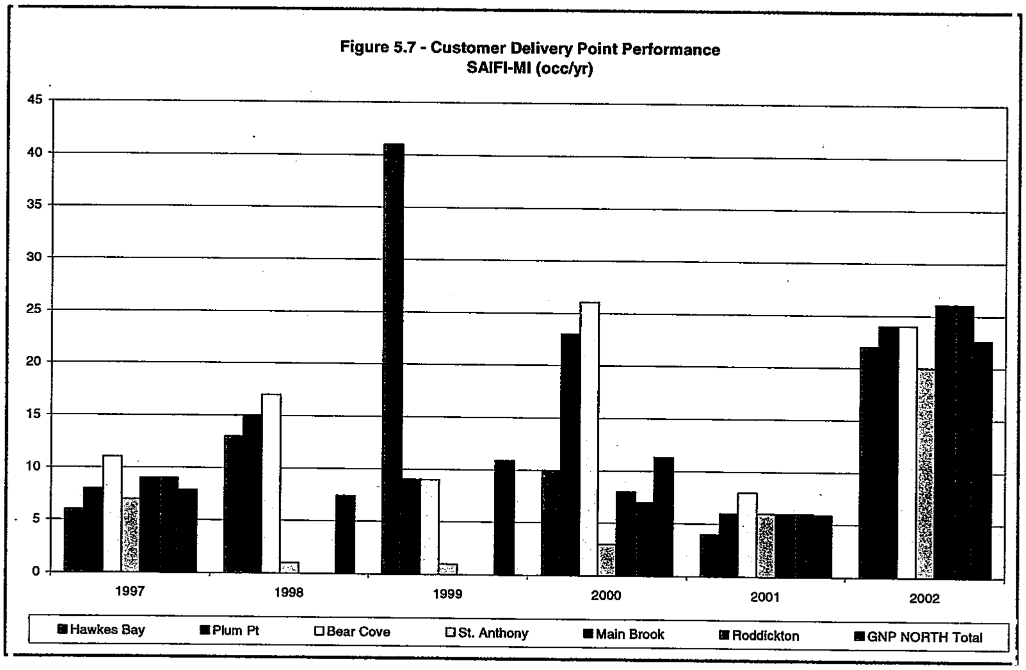
Figure 5.6 presents an overview of sustained interruptions frequency index SAIFI-SI and Figure 5.7 shows SAIFI-MI index for Momentary Interruptions. These indices correspond to a one-year performance of all the six delivery points at the customer level.

Figure 5.6 - Customer Delivery Point Performance
SAIFI-SI (occ/yr)



The results show that there are more sustained outages at St. Anthony, Main Brook and Roddickton delivery points as compared to Plum Point and Bear Cove during the early years. The difference is especially pronounced in Figure 5.6 for 2000. The underlying cause for this is lightning on TL241, which is explained in the Section 5.1.5. This also makes sense intuitively, as it is expected that the delivery points connected to the remote end of a radial supply would experience a higher frequency of interruptions due to their greater exposure. However, this enhanced impact is mainly due to the practice of manual closing of TL256 serving last three delivery points in the radial supply chain, as explained in the previous section. Please note that this trend has reversed in the last two years due to the use of of auto-reclosing of transmission elements north of Bear Cove.

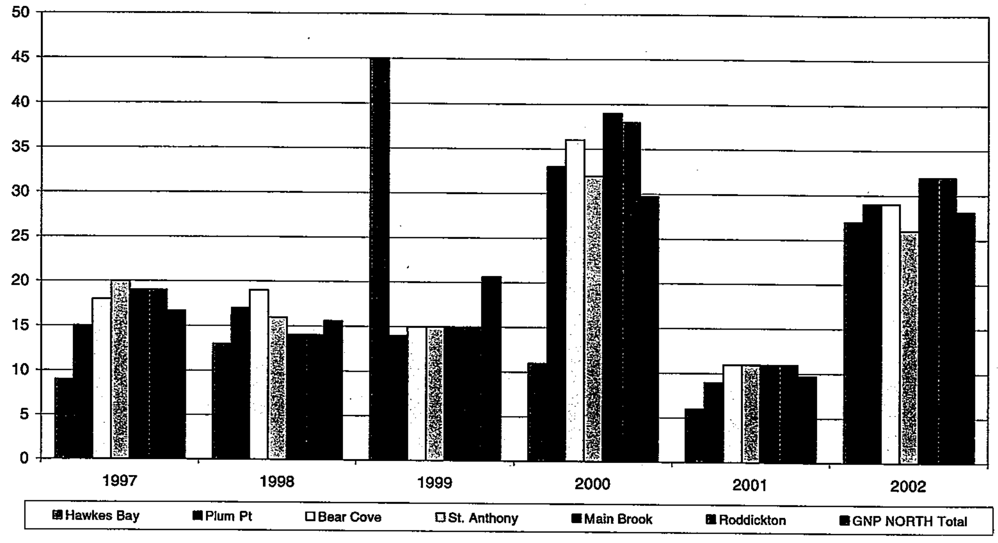
Prior to July 2001, the mix of sustained and momentary average frequency indices might have been different if the data logging had been done differently. This limitation in the data logging existed due to the current definition for momentary interruption as less than one-minute outage, and because of inherent delay in manual closing. Some North American utilities have adopted a modified definition for momentary interruptions, using a 5-minute duration as the threshold between momentary and sustained interruptions. Hydro has adhered strictly to the reporting criteria used by the Canadian Electricity Association, so the reduction in sustained outages and increase in momentary interruptions only occurred after the reclosing times were shortened for the more northerly circuits.



In 2002, the SAIFI-MI indices exhibit poor reliability performance for all the delivery points. In addition, the SAIFI- MI index value for Hawkes Bay is extremely high during 1999, as TL-227 69 kV circuit experienced a high number of interruptions due to adverse weather. The SAIFI-MI indices for Plum Point and Bear Cove delivery points are also quite high for 1998 and 2000 periods. In contrast, the SAIFI-MI indices for the other three delivery points demonstrate good performance during 1997 and 2001 periods but their performance declined in 2002. As discussed above, the reliability performance difference in the two sets of delivery points is primarily due to the use of manual closing on the northerly circuits prior to July 2001.

The collective (SAIFI-SI+MI) index values, as shown in Figure 5.8, support this conclusion since the performance difference among all the delivery points is generally very small but Hawkes Bay had extremely high index value in 1999. Except for 2001, the results of collective frequency interruptions index largely exceed the typical industry performance standards for the other five years analyzed. For example, Hydro One has a minimum performance standard of 9 occurrences per year (see Section 3.2, Table 3.1).

Figure 5.8 - Customer Delivery Point Performance
SAIFI-MI + SI (occ/yr)



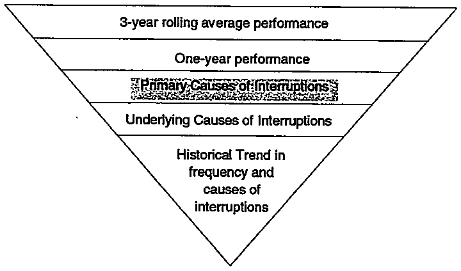
The average frequency index for combined sustained and momentary interruptions show a decreasing trend in the successive years up to 2001. However, the indices have jumped very high in 2000 and 2002. The reasons for these abrupt changes in index values have been investigated in Sections 5.1.3 and 5.1.4 below.

Intuitively, there should be more outages at the end of the line than at the beginning. However, in 1998, it appears that the northern communities were isolated onto the northern generation during storm conditions, thus sheltering the north from frequent outages along the coastal lines.

In conclusion, the average interruption duration for GNP North area customers has been below 2 hours/year during 1998, 1999 and 2000. However, this average rose to just over 3 hours during 2001 and 2002, which is still reasonable performance for any load that is supplied through a long radial feed. The SAIDI indices for Hawkes Bay indicate that its performance was poorer in 1999 and 2001 in comparison to other years, whereas Plum Point and Bear Cove delivery points experienced their worst performance in 1997 and 2001 respectively. The SAIDI values for St. Anthony, Main Brook and Roddickton delivery points demonstrate a consistently reasonable performance over the last five years. In addition, the reliability performance variation among these three delivery points is very small for the last three years. The performance of St. Anthony delivery point was best among the three in 2001.

Since July 2001, sustained interruptions in the GNP system have reduced significantly, however, the momentary interruptions rose to a high level in 2002 due to extreme weather conditions. The average number of momentary interruptions in the GNP region is generally higher in comparison to a typically acceptable level of performance in the electric supply industry. This will be reviewed in more detail in Section 5.2.1.

5.1.3 Primary Causes of Interruptions



The primary causes of delivery point interruptions are identified and discussed in this section. This analysis is focused on identification of those system elements, which have contributed most prominently to the overall performance of supply in the GNP North area. Further, the outages of identified system elements have been related to primary cause codes as per CEA classification for Transmission Equipment Forced Outages. These causes of interruptions are classified as, Defective Equipment, Adverse Weather, Adverse Environment, System Conditions, Human Element, Foreign Interference. The definitions of these causes are given in Appendix A.

The power supply source for Hawkes Bay delivery point normally consists of 138 kV lines TL239, TL259 and the 69 kV line TL221. The backup supply is provided by a combination of three 69 kV line sections, namely TL226, TL227 and TL221. Similarly, the transmission power supply source to the other five delivery points in the GNP North area consists of five 138 kV line sections, namely, TL239, TL259 and TL241, TL244, TL256 and two 69kV sections (TL261 and TL257). The TL227, TL221, TL259 and TL241 line sections run very close to the western coast of GNP and experience adverse weather and environmental conditions. The line sections north of Plum Point are relatively less exposed to such severe environmental conditions. The performance results of all the line sections, serving six delivery points, have been analyzed in detail and discussed below.

Causes for Interruption Duration

Table 5.2 relates delivery point outage durations to system equipment including transmission lines and terminal equipment. There were 5984 minutes of delivery point interruptions in 6 years. Bear Cove (BCV) was the most affected with 1283 minutes of the outage time and St. Anthony was the least impacted with an outage time of 674 minutes. The other four delivery points experienced interruptions between these two extremes.

Table 5.2: Delivery Point vs Equipment - Interruption Duration (min)
GNP North Area

Equipment	HBY	PPT	BCV	SDP	MBK	RWC	Sum
	Hawkes Bay	Plum Point	Bear Cove	St Anthony	Main Brook	Roddickton	
TL221	555						555
TL241		47	48	133	114	114	455
TL239	11	111	78	81	83	85	449
TL244			137	82	90	64	373
TL226	73	100	45	40	45	45	348
TL259	29	59	60	34	71	71	326
TL227	35	33	33	26	34	34	195
TL261				25	39	39	103
TL256				25	30	30	85
TL262	40			1	1	1	41
TL257	7			10	11	15	43
PPT stn		492	408	79	176	273	1,428
BES System	50	96	97	70	77	77	467
BCV stn			298	22	37	38	395
DLK stn	55	55	55	20	30	62	277
STA stn				28	111	125	264
Distribution System	87						87
HBYT3	13						13
Other	42	14	23				79
TL Total	750	351	402	455	517	498	2,973
Other Equipment	247	657	881	219	432	575	3,011
Total	997	1,008	1,283	674	949	1,073	5,984

It is evident from the table that the single largest contributor to delivery point interruption duration is outages caused by substation equipment at Plum Point, which caused 1428 minutes of delivery point interruptions. The most significant contributor to annual outage duration at Hawkes Bay was long outage durations due to TL221, and these incidents made TL 221 the second largest contributor to delivery point interruptions in the GNP North system. The third, fourth and fifth largest contributors are outages due to the BES system, then TL 241, then TL 239.

Table 5.3 presents similar results to Table 5.2 but the focus is on customer interruption minutes at each delivery point.

Table 5.3: Delivery Point vs Equipment - Interuption Duration (cust-min)
GNP North Area

Equipment	HBY	PPT	BCV	SDP	MBK	RWC	Sum	Prct
	Hawkes Bay	Plum Point	Bear Cove	St Anthony	Main Brook	Roddickton		
TL221	718,335						718,335	11.6
TL241		46,117	44,755	304,245	28,425	106,196	529,738	8.5
TL239	14,234	109,683	73,366	184,884	20,700	79,203	482,070	7.8
TL244			128,033	186,946	22,533	59,901	397,412	6.4
TL226	94,462	98,400	42,075	91,640	11,250	42,030	379,857	6.1
TL259	37,526	58,450	56,474	78,123	17,850	66,688	315,110	5.1
TL227	45,675	32,472	30,855	59,566	8,500	31,756	208,824	3.4
TL256				56,740	7,492	27,989	92,221	1.5
TL261				56,588	9,700	36,862	103,150	1.7
TL257	8,914			23,317	2,761	14,052	49,044	0.8
TL262	51,209			1,375	150	560	53,294	0.9
PPT stn		484,128	381,480	180,989	44,000	254,982	1,345,579	21.7
BES-sys	64,700	94,464	90,695	160,370	19,250	71,918	501,397	8.1
BCV stn			278,630	51,166	9.250	35,181	374,226	6.0
DLK stn	71,314	54,229	51,529	44,802	7,556	58,116	287,545	4.6
STA stn				63,384	27.833	116,750	207,968	3.3
D-sys	112,578						112,578	1.8
HBYT3	16,822						16,822	0.3
Other		13,929	21,713				35,642	0.6
TL Total	970,356	345,122	375,558	1,043,423	129,361	465,236	3,329,056	53.6
Other	265,414	646,750	824,047	500,711	107,889	536,946	2,881,757	46.4
Total	1,235,770	991,872	1,199,605	1,544,134	237,250	1,002,182	6,210,813	100.0
Prct TL	29.1	10.4	11.3	31.3	3.9	14.0	100.0	
Prct Other	9.2	22.4	28.6	17.4	3.7	18.6	100.0	
Prct Total	19.9	16.0	19.3	24.9	3.8	16.1	100.0	

Plum Point station faults were the single largest cause of customer interruption durations and contributed to about 21.7% of the total customer outage minutes in the GNP North area. The second largest contribution came from outages on TL 221 (11.6%), followed by TL 241 (8.5%) and the BES System (8.1%). Collectively, these four elements caused about 50% of the total customer-minutes of interruptions during the period. Contributions due to TL 239 (7.8%) TL244 (6.4%), TL 226 (6.1%), Bear Cove Station (6.0%) and Deer Lake Station (4.6%) explain over 30% of the total customer-minutes of interruptions.

It is interesting to note that St. Anthony was the least affected delivery point in terms of total duration of outage, but it experienced the highest number of customer interruption minutes, amounting to 25% in the GNP North area. Main Brook is the least affected delivery point in terms of customer minutes, as it serves less number of customers.

Table 5.4 relates the primary causes of interruptions on the transmission elements and the total outage duration caused by each of the elements. As in Table 5.3, the largest contributors to customer interruptions, totaling 80% of all customer-minutes in the GNP North area, are highlighted in Table 5.4.

Table 5.4: Primary Cause vs Equipment - Interuption Duration (cust-min)
GNP North Area

Equipment	Adverse Environment	Adverse Weather	Defective Equipment	Foregn Interference	Human Element	System Conditions	Unknown	Sum	Prct
TL221		357,309	361,026					718,335	11.6
TL241	6,950	358,432	74,368		10,425	76,088	3,475	529,738	8.5
TL239	10,425	471,645						482,070	7.8
TL244		148,900	5,547	209,655	15,221		18,089	397,412	6.4
TL226	379,857							379,857	6.1
TL259		41,614	259,596				13,900	315,110	5.1
TL227		4,267	204,557					208,824	3.4
TL256		13,416	65,539		13,266			92,221	1.5
TL261		103,150						103,150	1.7
TL262		49,044						49,044	0.8
TL257		53,294						53,294	0.9
PPT stn			998,850		346,729			1,345,579	21.7
BES-sys						501,397		501,397	8.1
BCV stn			358,820		15,407			374,226	6.0
DLK stn		287,545						287,545	4.6
STA stn			125,113		82,855			207,968	3.3
D-sys						112,578		112,578	1.8
HBYT3			16,822					16,822	0.3
Other		6,853	4,215			22,550	2,023	35,642	0.6
TL Total	397,232	1,601,072	970,634	209,655	38,912	76,088	35,464	3,329,056	53.6
Other Equipment		294,398	1,503,820		444,990	636,525	2,023	2,881,757	46.4
Total	397,232	1,895,469	2,474,454	209,655	483,902	712,613	37,487	6,210,813	100.0
Prct TL	11.9	48.1	29.2	6.3	1.2	2.3	1.1	100.0	
Prct Other		10.2	52.2		15.4	22.1	0.1	100.0	
Prct Total	6.4	30.5	39.8	3.4	7.8	11.5	0.6	100.0	

As expected, the sum of the interruption time over all interruption causes for each circuit is identical to the sum of all delivery point interruption times over all delivery points as presented in Table 5.3. The most prevalent primary cause is defective equipment at 39.8% of all customer-minutes in GNP North, which accounted for over 50% of all outages at substations. The second most important cause is adverse weather (30.5% of all customer-minutes), with particular emphasis on circuits TL 239, TL 241 and TL 221. The third most important cause is system conditions adjacent to the GNP area (11.5 % of all customer-minutes), which led to interruptions due to the BES system. Overall in the GNP North area, 53.6% of customer outage time is attributable to the transmission lines and 46.4% is attributable to other equipment related outages.

In summary, Tables 5.2 to 5.4 reveal that the largest sources of total customer interruption time over the six-year period as:

- Defective equipment at Plum Point Substation (distribution recloser malfunction caused transmission equipment protection to operate)
- Adverse weather on TL239
- Defective equipment on TL 221 (faulty insulator)
- Adverse environment on TL226
- Defective equipment at Bear Cove Station (Corrosion on gas pressure relay connector)
- Defective equipment on TL 259 (broken cross arm during storm conditions)
- Adverse weather on TL241
- Adverse weather on TL221
- Human Element at Plum Point Substation

Causes for Interruption Frequency

Table 5.5 summarizes the sustained and momentary interruptions, as it relates to delivery point and system equipment. There were 735 delivery point outages during the 6 years period from June 1st 1997 and May 31st 2003. All the delivery points were affected more or less in the same way with least amount of interruptions occurring at Hawkes Bay. Looking at the equipment at fault, TL241 had 195 delivery point occurrences charged against it. The other main elements that are responsible for the majority of delivery point interruptions are TL 239, TL259, TL244, TL227 and TL221 in descending

Table 5.5: Delivery Point vs Equipment - Interruption Frequency (occ)
Sustained and Momentary Interruptions in the GNP North Area

Equipment	HBY HawkesBay	PPT PlumPoint	BCV BearCove	SDP StAnthony	MBK MainBrooks	RWC Roddickton	Sum
TL241		38	40	36	39	39	192
TL239	26	26	26	26	26	26	157
TL259	23	25	25	20	25	25	142
TL244			12	11	13	12	49
TL227	8	9	8	2	2	2	30
TL221	29						29
TL256				5	5	5	15
TL257				2	7	7	16
TL262	13		1	1	1	1	15
TL226	2	2	2	2	2	2	10
TL261				4	2	1	7
PPT stn		5	4	4	4	4	21
BCV stn			2	3	3	3	11
BES-sys	1	1	1	2	1	1	7
DLK stn	1	1	1	1	1	1	5
STA stn				2	1	1	4
D-sys	1						1
HBYT3	1						1
Other	6	11	7				23
TL Total	101	100	113	108	120	119	661
Other Equipment	10	17	15	12	10	10	74
Total	111	117	128	120	130	129	735

order. TL241 and TL239 alone caused almost 50% of the delivery point interruptions, while the six elements listed above caused over 80% of all delivery point interruptions in the GNP North area.

Table 5.6 presents similar results to Table 5.5 but the focus is customer interruption occurrences at each delivery point. Two 138 kV line sections TL241 and TL239 were the major cause for customer interruptions and contributed to almost 50% of the total customer outage occurrences in the GNP North area. The other noteworthy contributors to the customer outage frequency are TL259, TL244, TL221 and TL227 circuits, and the sum of the contributions from all six circuits above accounted for over 80% of all customer interruptions in the GNP North area.

Table 5.6: Delivery Point vs Equipment - Interuption Frequency (cust-occ)

Sustained and Momentary Interruptions in the GNP North Area

Equipment	HBY	PPT	BCV	SDP	MBK	RWC	Sum	Prct
	Hawkes Bay	Plum Point	Bear Cove	St Anthony	Main Brook	Roddickton		
TL241		37,687	36,995	83,087	9,700	36,239	203,708	25.3
TL239	33,262	25,851	24,626	59,882	6,568	24,538	174,727	21.7
TL259	29,633	24,206	23,188	46,278	6,150	22,976	152,432	18.9
TL244			11,594	25,965	3,150	11,457	52,166	6.5
TL221	37,939						37,939	4.7
TL227	10,946	8,575	7,213	3,927	429	1,601	32,691	4.1
TL262	16,739			1,375	150	560	18,824	2.3
TL256				10,691	1,233	4,608	16,532	2.1
TL257			1,849	4,378	1,794	6,393	14,415	1.8
TL261				8,935	425	1,276	10,636	1.3
TL226	2,218	1,687	1,603	3,927	429	1,601	11,465	1.4
PPT stn		4,920	3,740	9,164	1,000	3,736	22,560	2.8
BCV stn			2,182	6,873	667	2,491	12,212	1.5
BES System	1,294	984	935	4,582	250	934	8,979	1.1
DLK stn	1,150	875	831	2,036	222	830	5,945	0.7
STA stn				3,818	333	1,245	5,397	0.7
Distribution System	1,294						1,294	0.2
HBYT3	1,294						1,294	0.2
Other	7,865	10,343	4,924				23,132	2.9
TL Total	130,737	98,006	107,068	248,446	30,028	111,250	725,535	90.0
Other	12,897	17,122	12,612	26,474	2,472	9,236	80,813	10.0
Total	143,634	115,128	119,680	274,920	32,500	120,486	806,348	100.0
Prct TL	18.0	13.5	14.8	34.2	4.1	15.3	100.0	
Prct Other	16.0	21.2	15.6	32.8	3.1	11.4	100.0	
Prct Total	17.8	14.3	14.8	34.1	4.0	14.9	100.0	

St. Anthony customers experienced the highest number of customer interruptions, amounting to 34.1% in the GNP north area. Again, Main Brook is the least impacted in terms of customer occurrences. Overall in the GNP North area, about 90% of customer interruptions are transmission related and only 10% are attributable to other equipment causes.

Table 5.7 is a similar presentation of the total customer interruptions by primary causes and the corresponding equipment interrupted.

As can be seen, the following are the dominant sources of customer interruptions over the six-year period:

- Adverse weather on TL241
- Adverse weather on TL239

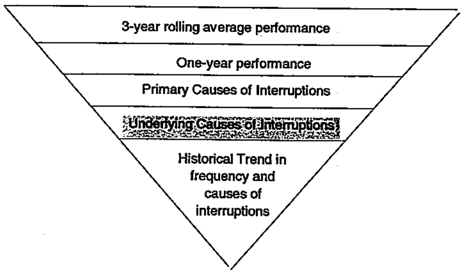
- Adverse weather on TL259
- Defective equipment on TL259 (Jumper contacting cross arm)
- Adverse weather on TL221
- Adverse weather on TL244
- Adverse weather on TL227

The first three equipment/cause combinations account for almost 50% of total customer interruptions in the GNP North area. All seven equipment/cause combinations account for almost 70% of all customer interruptions in the GNP North area.

Table 5.7: Primary Cause vs Equipment - Interruption Frequency (cust-occ)
Sustained and Momentary Interruptions in the GNP North Area

Equipment	Adverse Environment	Adverse Weather	Defective Equipment	Foreign Interference	Human Element	System Conditions	Unknown	Sum	Prct
TL241	5,276	161,503	5,276		10,551	5,276	15,827	203,708	25.3
TL239	6,688	161,351					6,688	174,727	21.7
TL259		67,964	64,404				20,064	152,432	18.9
TL244		24,689	3,595	6,642	1,326		15,914	52,166	6.5
TL221		35,351	1,294				1,294	37,939	4.7
TL227		26,003	6,688					32,691	4.1
TL256		12,019	5,698		1,107			18,824	2.3
TL262		16,532						16,532	2.1
TL257		14,415						14,415	1.8
TL261		10,636						10,636	1.3
TL226	6,688	4,777						11,465	1.4
PPT stn			17,166		5,394			22,560	2.8
BGV stn			10,742		1,470			12,212	1.5
BES-sys						8,979		8,979	1.1
DLK stn		5,945						5,945	0.7
STA stn			3,475		1,922			5,397	0.7
D-sys						1,294		1,294	0.2
HBYT3			1,294					1,294	0.2
Other		16,969.2	2,379.9				3,782.8	23,132	2.9
TL Total	18,652	535,241	86,955	6,642	12,984	5,276	59,787	725,535	90.0
Other Equipment		22,914	35,057		8,786	10,273	3,783	80,813	10.0
Total	18,652	558,155	122,012	6,642	21,770	15,549	63,569	806,348	100.0
Prct TL	2.6	73.8	12.0	0.9	1.8	0.7	8.2	100.0	
Prct Other		28.4	43.4		10.9	12.7	4.7	100.0	
Prct Total	2.3	69.2	15.1	0.8	2.7	1.9	7.9	100.0	

5.1.4 Underlying Causes of Interruptions

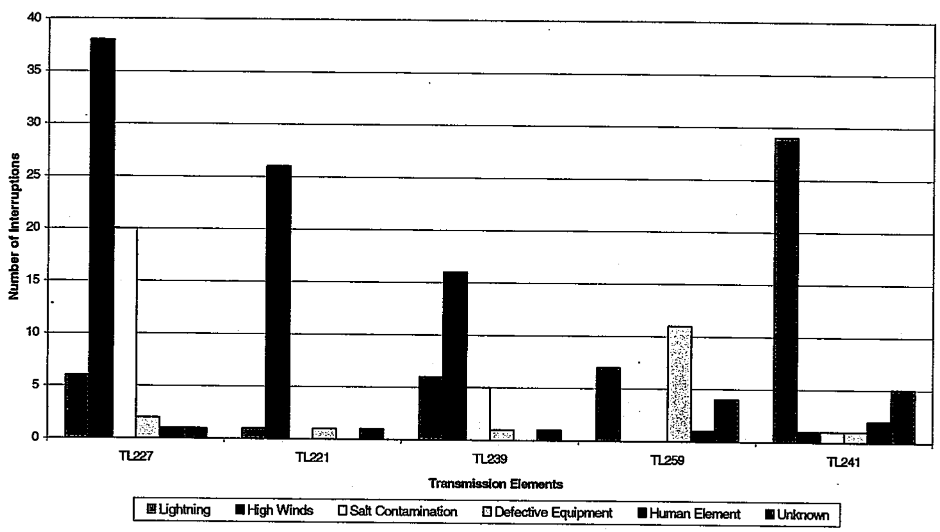


It should be noted that sections 5.1.1 to 5.1.3 discussed delivery point information, namely, customer duration and occurrence numbers. This section discusses transmission line events. The difference is highlighted by an example. Consider an event on TL241 involving two momentary outages in short succession (for example high winds), but affected various customers. If customers at Plum Point, Bear Cove, St. Anthony, Main Brook and Roddickton were affected (namely 5394 customers twice), the previous section would have logged 10,788 customer interruptions. As the impact of an event depends on the BES configuration, there is no general rule for relating numbers from the previous section to those in the following sections (5.1.4, 5.1.5).

Or, in other words, the impact of an event depends on the system configuration. So an outage on a specific piece of equipment may not have a corresponding customer impact. The information in this section focuses on equipment performance rather than delivery point performance.

Over a six-year period from January 1st, 1997 and December 31st, 2002, Figure 5.9 shows the number of interruptions that occurred on different transmission line sections of the GNP region and presents their underlying causes of interruptions.

Figure 5.9 Underlying Causes of Interruptions over 6 years



The results indicate that most of these interruptions occurred on the 69 kV line sections and the majority of them were caused by high winds and salt spray instigating insulation failure. It is pertinent to note that the outage of TL227 rarely affects six delivery points in the GNP North area. For reference, TL221 only affects Hawkes Bay, because of its radial nature.

The southern section (TL-239) of 138 kV line also experienced a high number of interruptions due to the same underlying cause.

Across the entire GNP region, the second major underlying cause of transmission line interruptions is lightning. The largest individual contributors are as follows:

- High winds on TL227 but impacted mainly Hawkes Bay out of six delivery points monitored
- High winds on TL221 but impacted Hawkes Bay only
- Lightning on TL241
- High winds on TL239
- Defective equipment on TL259 (Jumper contacting cross arm)

5.1.5 Historical Trend in Number and Causes of Interruptions

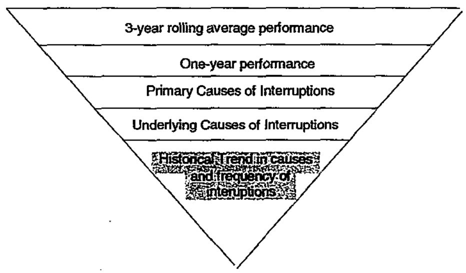
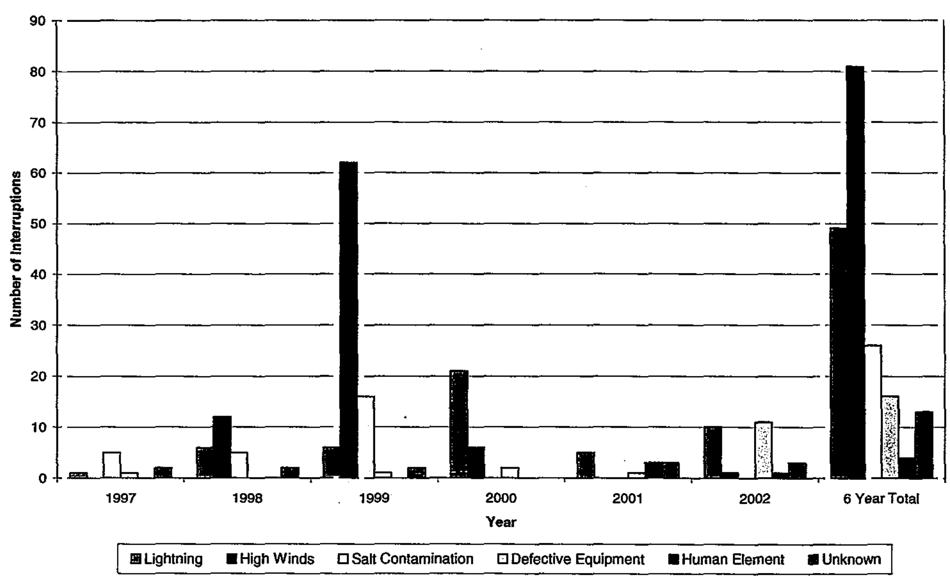


Figure 5.10 (next page) presents the historical results for underlying causes of interruptions for a six-year period. The largest number of interruptions occurred in1999, and most of these were caused by high winds, and the second largest number occurred in 2000, which were predominantly caused by lightning. The causes of other interruptions are small in number. The results show that the lowest number of interruptions occurred in 2001.

Figure 5.10 Historical Trend in Number and Causes of Interruptions



The transmission line interruptions due to high winds and salt spray have reduced significantly during the last three years. In particular, the following projects have helped reduce these occurrences that are further discussed in Section 5.3:

1) Replacement of insulators on TL239 in 1999
2) Rerouting of entire TL262 line in 2001
3) Partial replacement of insulators on TL226 and TL227 during 2001 and 2002

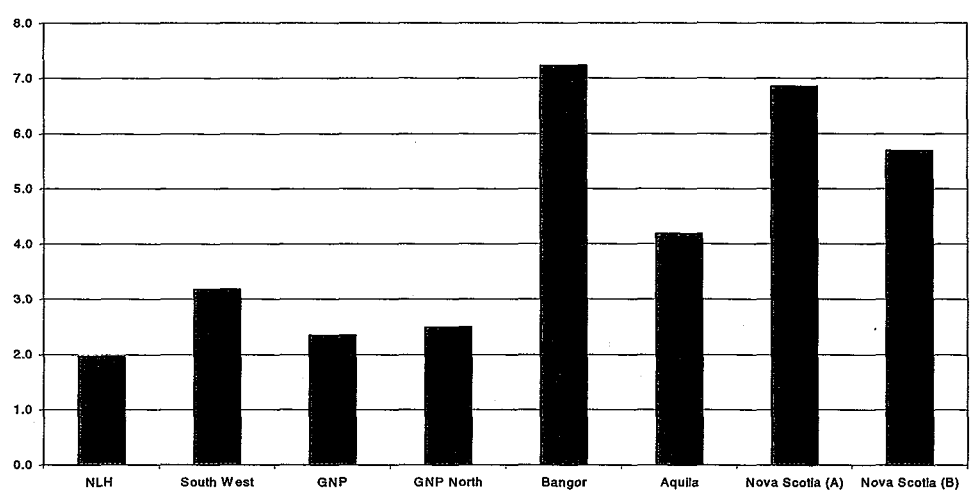
5.2 Comparison of Hydro Statistics with Other Utilities

This section compares Hydro's delivery point performances in terms of five-year averages to the CEA five-year averages and three North American utilities. In addition, transmission network performance of GNP North area in terms of frequency of outages has been compared with the other radial circuits within Hydro system operating in similar circumstances and with national averages for same voltage class, which is compiled by CEA. Supporting information from the CEA 5-year summary report is included in Appendix C.

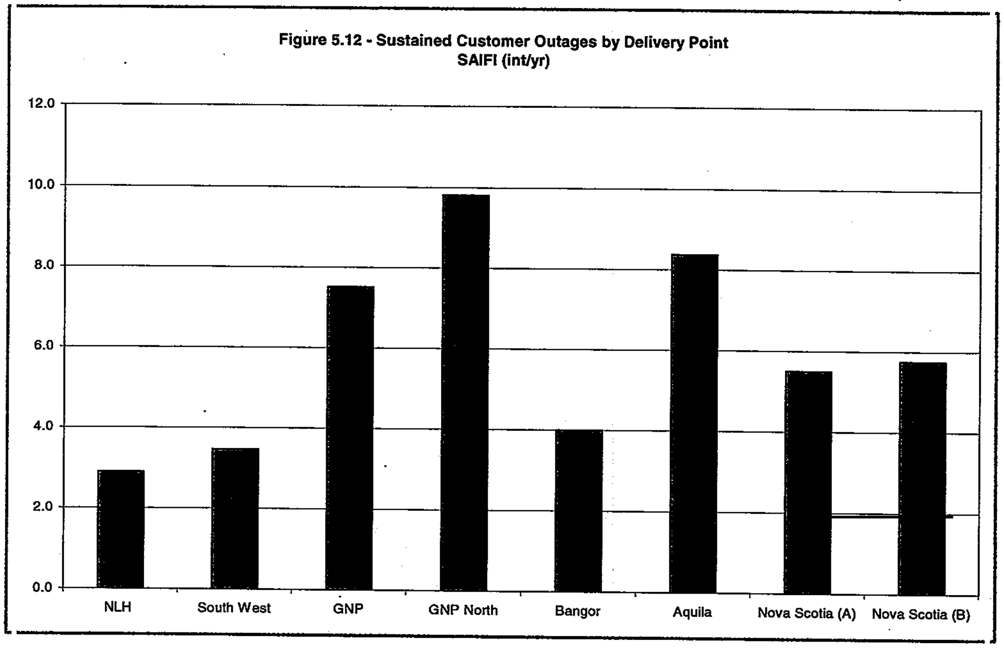
5.2.1 Delivery Point Performance Served by Single Circuits

For the GNP and GNP North areas, primarily two performance indices SAIDI and SAIFI have been evaluated and compared with other circuits within Hydro system and other utilities operating similar circuits in comparable circumstances. Figure 5.11 compares delivery point SAIDI values for five-year data. The graph below show that GNP North area compares favorably with Hydro statistics and the SAIDI values are significantly low in comparison to three other utilities.

Figure 5.11 - Sustained Customer Outages by Delivery Point
SAIDI (hrs/yr)



Similarly, Figure 5.12 shows a comparison of delivery point SAIFI values for those delivery points that are served by radial circuits operating in similar circumstances. The results indicate that the GNP North area values are the highest among the sample. This is mainly due to the fact that the delivery points in the GNP region are served by a significantly longer radial circuit among all compared.



5.2.2 Transmission Lines Performance Comparisons Operating Under Similar Circumstances

Figure 5.13 shows the average duration of interruption in hours for each occurrence. Hydro transmission line statistics are averaged over a six-year period (June 1997 to May 2003) whereas statistics of other sources are averaged over the longest time period available (typically 4 or 5 years).

One event was excluded from the Hydro data: TL 220, March 4th, 1998, involving a structure, whose outage duration was just over 61 hours. This was an extreme event. In 1999 TL220 was relocated to improve access. This delay in restoration is not expected to re-occur in the future. If this event were excluded, the new average outage duration would be 0.03 hours, or 2 minutes.

The results indicate that almost all the Hydro transmission circuits (except TL259) outperformed in terms of average annual interruption duration in comparison to the circuits belonging to other utilities and in comparison to the CEA average for similar types of circuits. The circuit TL259 had one major event on Sept 12th, 2002 that lasted for almost 7 hours, and was attributed to defective equipment (broken cross arm). If this event were excluded, the average outage duration would be 17.5 minutes, or 0.29 hours.

This suggests that Hydro maintains and restores their radial transmission circuits in an efficient manner when subjected to sustained outages on their circuits, excluding of course extreme events.

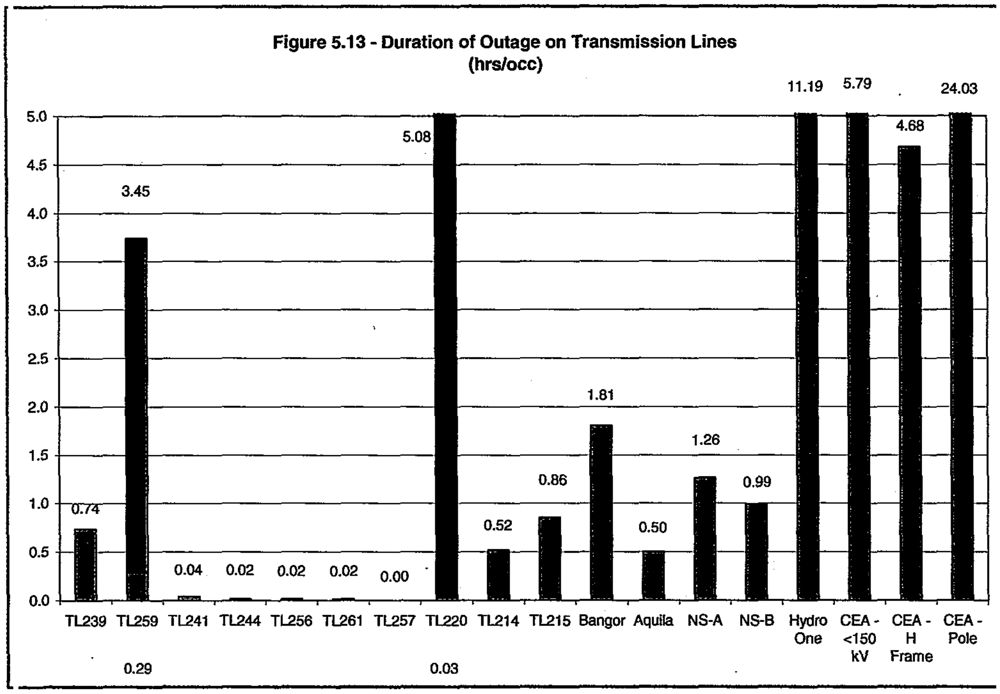
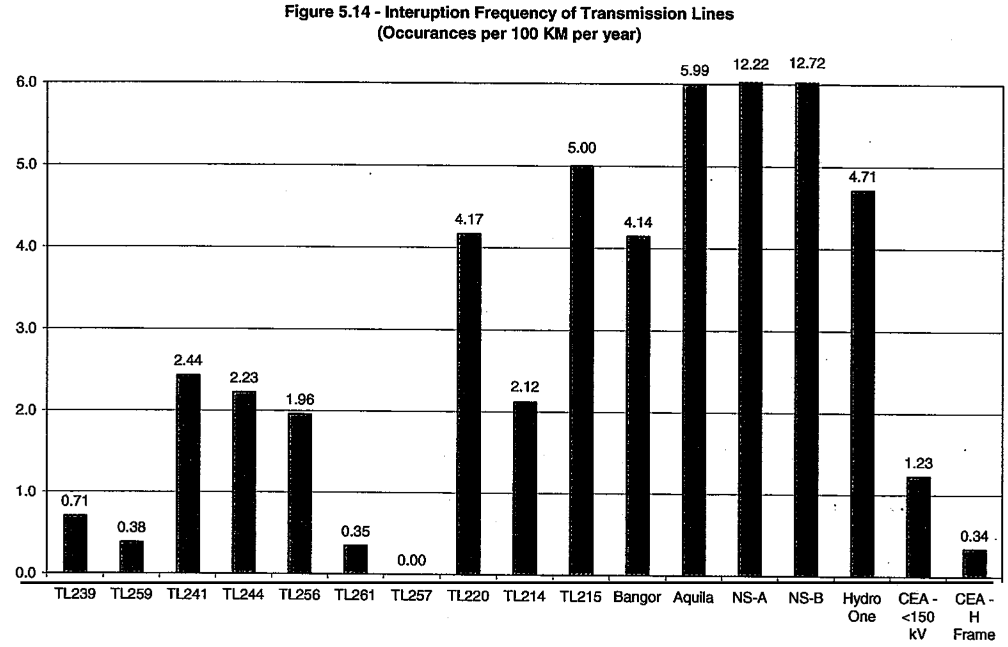


Figure 5.14 shows frequency of sustained occurrences per 100 km for each of the line sections serving the GNP and South West Regions in Hydro's system. The statistics for five similar circuits from four different utilities and CEA statistics enumerating the average frequency of interruption for all reporting utilities are also shown on the graph. As before, an event on TL220 has been excluded.

The figure below shows that the frequency of interruptions for five sections of the 138 kV transmission circuit is relatively high in comparison to the last two sections of 69 kV circuit that serve St. Anthony and Roddickton communities. This is due to the lower level of exposure to the extreme weather and environmental conditions. Within the Hydro system, the frequency of interruption results for the GNP transmission circuits are much better than the frequency statistics of the transmission lines serving South West region and TL-220 circuit. The performance is also better than the Nova Scotia Power circuit that operates in a similar environment. In addition, the GNP transmission system performance is relatively better in comparison to the circuits belonging to Bangor Hydro, Aquila and Hydro One Networks. It may be recognized that these circuits may be radial but their operating environment is relatively less severe.



5.3 Impact Assessment of Previous Investments and Maintenance

From the previous analysis, it is evident that the outage duration (average annual and average per outage) is within normal acceptable utility practices, however outage frequency is higher than normal acceptable utility practice.

Hydro has implemented a number of projects to maintain and improve the performance (frequency) of GNP transmission system. The most significant was the replacement of insulators on TL239 line in 1999 and increasing the minimum leakage distance to 130 inches instead of 90 inches, as this line passes through high contamination areas. In the last two years, the insulators were also replaced on lines TL226 and TL227 in addition to the replacement of some of the structures in different sections of the route. The results in Figure 5.10 show a significant reduction in number of interruptions (frequency) due to high winds and lightning on the GNP transmission system.

Historically, adverse weather has been the major cause of interruptions on the GNP transmission system. It is likely to be the main cause of the interruption problem in future too.

5.4 Sustainable Delivery Point Performance

Historical SAIDI statistics for Hawkes Bay, Plum Point and Bear Cove delivery points show that year-to-year performance of these delivery points vary quite considerably due to yearly weather variations. At the same time, the reliability performance of St. Anthony, Main Brook and Roddickton delivery points has been fairly consistent for the past three years. This is primarily due to the standby generation contribution during the sustained outages in the BES system.

Over the past six-year period, especially in the recent years, the SAIFI indices for all the delivery points in the GNP north area are quite similar. Table 5.8 below gives an overview of the expected reliability performance of six delivery points in future years.

Table 5.8 Sustainable Reliability Performance in the GNP north Area

Reliability Performance Measure	Hawkes Bay	Plum Point	Bear Cove	St. Anthony	Main Brook	Roddickton
SAIDI (hr/year)	≤ 3	≤ 3	≤ 3.5	≤ 2.5	≤ 2.5	≤ 2.5
SAIFI – SI (occ/year)	≤ 3	≤ 5.5	≤ 6	≤ 6	≤ 6	≤ 6
SAIFI – MI (occ/year)	≤ 15	≤ 13	≤ 14	≤ 15	≤ 15	≤ 15

The reliability performance estimates mentioned in the above table are based on the six-year performance statistics. It is expected that the Hydro will maintain their transmission and generation facilities as per the typical industry practices. Therefore, it can safely be said that the above performance levels for each delivery point are sustainable.

5.5 Recommendations

The outage history indicates that the underlying causes for most of the interruptions on the GNP transmission system are attributed to high winds and lightning. Principally, these outages correspond to outside physical forces on which Hydro has no direct control.

However, the most significant cause for transmission supply related outages (sustained interruptions) has been attributed to station equipment failures. This accounts for 40% of the interruption duration and only 15% of the interruption frequency.

The second leading cause is adverse weather with duration of interruptions at 30% and frequency of interruption at 70%.

Accordingly, the following is recommended in order to reduce the number of outages in future:

- Proactively maintain the protection and control equipment at stations serving the GNP North area to reduce the sustained interruption times.
- Review the lightning statistics and identify locations on TL241 where shield wires or lightning arresters might be installed to reduce momentary interruptions on this long section of the 138 kV circuit.
- Identify the most exposed sections of circuits TL227, TL221 and TL239 to high winds, and implement corrective measures: for example, applying phase spacers or structure rebuilds to reduce the probability of phase slapping.

With respect to these recommendations, Hydro has been proactive and some corrective actions had already been taken by the time this study was commissioned. Hydro is using its FALLS lightning analysis software to study lightning activity on the GNP and assist in the identification of performance improvement initiatives. Furthermore, in 1999 and 2000/01, TL 239 and TL 227 were partially re-insulated and structures modified in the most exposed areas to eliminate salt contamination and line slapping problems.

6. Standby Generation Analysis

6 Standby Generation Analysis

The following sections analyze the contribution of the existing standby generation at Hawkes Bay, St. Anthony, and Roddickton, and discuss the impact of this generation on reliability performance in the GNP North area.

6.1 Impact of Existing Standby Generation on Reliability Performance

Table 6.1 (Hawkes Bay), Table 6.2 (St. Anthony) and Table 6.3 (Roddickton) present the results of actual operation of the existing standby generation at the delivery points during the last six years for unplanned outages in the BES system.

The results indicate that the standby generation at Hawkes Bay was operated in 1999 and 2002 and supplied power to the local customers for a total duration of 2 hours and 20 minutes. Over a six-year period, the standby generation at Hawkes Bay operated for merely 12% of the time in relation to the total unplanned outage time, which is quite low.

Table 6.1 Hawkes Bay Standby Generation Contribution (Unplanned Outages)

Duration in Minutes				
BES	DP	Gen ON	Date	Time
279	279		2001-Aug-19	0032
208	119	89	1999-Oct-17	1048
110	73	37	1999-Oct-24	0747
94	94		2003-Mar-04	1256
93	93		1997-Jul-29	0125
87	87		1999-Nov-28	0050
71	71		2001-Jul-13	1314
64	60	4	2002-Aug-13	1400
36	36		1999-Oct-17	0956
35	25	10	2002-Nov-18	1813
32	32		2000-Sep-27	1402
13	13		2002-Jun-17	1447
10	10		1998-Mar-23	0058
4	4		2002-Sep-12	0610
1	1		1998-Mar-23	0056
1,137	997	140	= table sum	
			= other events	
1,137	997	140		

Hydro submitted an explanation to this effect that it is only after about 15 to 20 minutes outage, does the control center ask for Hawkes Bay diesels to be put in service. Of the 15 events in Table 6.1, there were 4 less than 15 minutes when the diesels would not have been asked for. Of the remaining 11 events where the diesels would have been asked for, 4 out of 11 times they were used and 7 out of 11 times they were unavailable. The unavailability was due to operational problems such as; distribution problems on the Hawkes Bay system and control problems with the diesel units. This caused increased outage durations in some situations. Hydro staff confirmed that they are currently working to resolve these operational and control problems to improve the availability of the units.

In contrast, during the same period, the standby generation at St. Anthony delivery point reduced the total outage duration of St. Anthony delivery point by more than half. Except for two instances, the results show that the standby generation was generally turned on only for a sustained outage of more than 20 minutes.

Table 6.2 St. Anthony Standby Generation Contribution (Unplanned Outages)

Minutes of Duration				
BES	DP	Gen ON	Date	Time
123	20	103	2000-Aug-25	1921
100	40	60	1999-Oct-24	0747
98	15	83	1997-Jun-02	2059
97	64	33	2003-Mar-04	1256
84	9	75	2001-Apr-06	0615
82	54	28	1998-Mar-23	0058
72		72	2002-Nov-18	1813
71	22	49	2002-Aug-13	1400
65	33	32	1997-Oct-29	1338
60	31	29	1997-Jul-19	1311
52	52		1997-Jun-27	0604
47	19	28	2002-Sep-12	0610
47	25	22	1997-Jul-19	1411
39	22	17	1999-Oct-25	1053
34	26	8	2000-Sep-27	1402
20	20		2002-Jul-06	0455
16	16		1997-Jun-27	1526
15	15		1998-Sep-01	0946
13	13		2000-Aug-05	0025
12	12		2000-Jul-19	1344
11	15		2002-May-04	0751
11	11		2000-Jul-19	1252
1,169	534	639	= table sum	
126	140		= other events	
1,295	674			

However, the generation at Roddickton took a longer time to start, and its contribution to reduce the total outage time is only about 22%. Again, this low percent use of Roddickton diesel units may be further explained by putting things in the context of the number of events. Referring to Table 6.3, 7 out of 21 events were 20 minutes or less so the diesels would not have been asked for to deliver power. For 8 out of 21 events the Roddickton diesels were either unavailable or the load could have been supplied from St. Anthony so the diesels were not asked for. And for the remaining 6 out of 21 events, the Roddickton diesels were asked for and they delivered.

Table 6.3 Roddickton Standby Generation Contribution (Unplanned Outages)

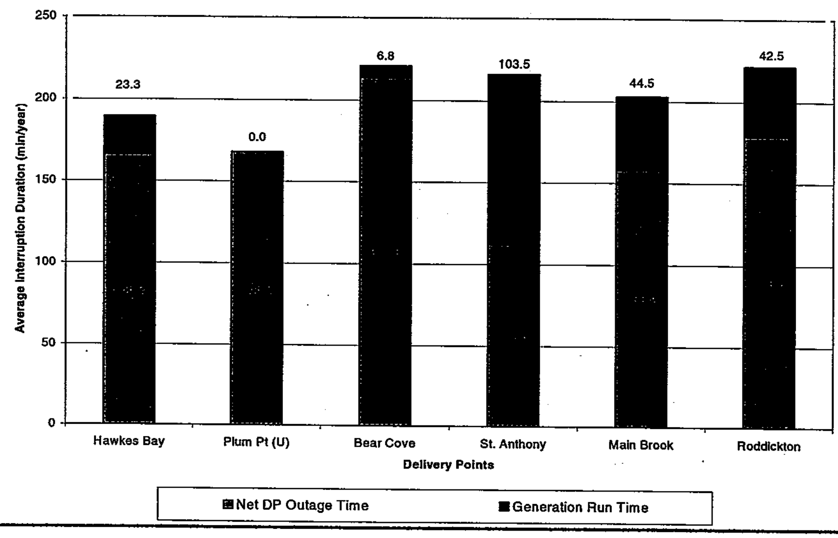
Minutes of Duration				
BES	DP	Gen ON	Date	Time
123	25	98	2000-Aug-25	1921
120	141		2002-May-04	0751
107	102	5	1997-Jul-19	1311
100	45	55	1999-Oct-24	0747
98	45	53	1997-Jun-02	2059
97	77	20	2003-Mar-04	1256
80	91		2001-Apr-06	0615
72	9	63	2002-Nov-18	1813
70	70		2002-Aug-13	1400
58	58		1998-Mar-23	0058
57	57		1997-Oct-29	1338
50	54		2002-May-04	2038
47	47		2002-Sep-12	0610
34	34		2000-Sep-27	1402
20	20		2002-Jul-06	0455
18	21		2002-May-04	1235
17	17		1999-Oct-25	1053
15	15		1998-Sep-01	0946
12	12		2000-Jul-19	1344
11	11		2000-Aug-05	0025
11	11		2000-Jul-19	1252
1,217	962	294	= table sum	
111	111		= other events	
1,328	1,073			

The average annual duration of interruption for each delivery point in the GNP North area is shown in Figure 6.1. The graph shows the contribution of standby generation as a red bar, which reduced the average outage time for each delivery point to the levels shown as blue bars. The figure clearly demonstrates the significant contribution of St. Anthony standby generation in reducing the value of SAIDI for St. Anthony. At the same time, Roddickton standby generation did not reduce the SAIDI value at Roddickton as much.

As indicated above, this low contribution is primarily due to the delayed synchronization of Roddickton generation to the BES in cases of sustained outages. Moving this generation to St. Anthony may obviate this limitation since the historical results show that TL261 and TL257 are very reliable and had negligible number and duration of interruptions over the past six-year period. This action is likely to increase the reliability performance of Roddickton delivery point.

Based on the historical performance of the lines TL261 and TL257, Acres is of the view that consolidating standby generation at St. Anthony would reduce the average duration of outage time at Main Brook and Roddickton delivery points. The existing arrangement actually contributes to the degradation of reliability performance at these delivery points.

Figure 6.1 -Standby Generation Contribution in Delivery Point Performance



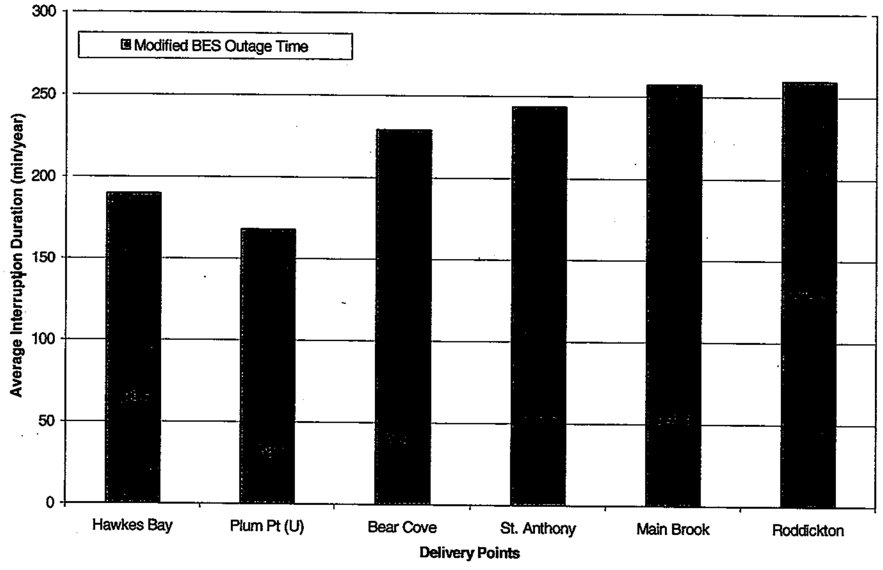
A review of each of the occurrences in Tables 6.1, 6.2 and 6.3 was also carried out. Each event where generation was on-line, and as such, the load was disconnected from the BES, was analyzed for correlation with occurrences of transmission system interruptions (momentary or sustained). In situations where a correlation was found, it is evident that the generation was not being used in a preventative manner, but rather as a reaction to power no longer being available from the BES. Hydro's standard mode of operation is to use St. Anthony generation mainly to reduce duration when there are frequency interruptions due to lightning, for example, from points farther south on the system. As a result, the generation did not have an impact on the frequency of interruption.

6.2 Delivery Point Performance without Standby Generation

Figure 6.2 shows the impact on delivery point reliability performance if the standby generation were removed from Hawkes Bay, St. Anthony and Roddickton diesel plants. The results are based on the historical reliability performance and predictive reliability assessment of three northern delivery points, as discussed in Chapter 5.

St. Anthony delivery point experiences the highest reliability impact, as the average annual duration of interruptions increased by more than 100%. Similarly, reliability performance of Main Brook and Roddickton delivery points would deteriorate significantly with the complete removal of generation from Roddickton, as being the primary source of standby generation. However, as per the past experience, the impact on Hawkes Bay reliability performance is not that significant. But the impact would have been more if the generation had dispatched after the usual time delay during sustained outages. There is an insignificant impact of standby generation on Plum Point and Bear Cove delivery points.

Figure 6.2 - Delivery Point Performance without Standby Generation



At the same time, it is worthwhile to mention that these reliability indices, in respect of all the six delivery points, are well within the minimum performance standards followed in other parts of the country.

6.3 Assessment of Standby Generation Requirement

Historically, the existing standby generation was able to supply 100% of the demand in GNP North area for more than 95% of the time. The generation at Hawkes Bay, St. Anthony and Roddickton is not sufficient for full backup, but rather provides short-term relief (standby) for some critical loads during emergency conditions.

Critical loads are usually emergency services that would be required during a prolonged outage. This generally does not include industry, whereas in some cases, it includes residential customers on a rotating basis. It does include Hospitals, Long Term Care Facilities, Water/Sewage Systems, and other emergency response facilities. In almost all jurisdictions the critical load is usually less than 25% of the peak load.

Accordingly, the GNP North area load forecast provided by Hydro was examined and compared to the available standby generation at Hawkes Bay, St. Anthony and Roddickton. It was recognized that the typical essential load at these three locations is lower than the existing capacity of standby generation in the GNP North area. Hence, in view of the reasonable margin between essential loads and standby generation, and the historical results of reliability statistics, it is concluded that no additional generation is needed in the near future.

6.4 Portable Versus Fixed Standby Generation

Historical reliability performance results of the six delivery points in the North GNP area show that their performance compares favorably with the delivery points in other jurisdictions, even after excluding the impact of standby generation. Hence, justification for any new fixed generation cannot be established. If any additional generation were to be considered, portable generation would provide the greatest benefits. Portable generation can be used to serve the essential load of those communities with an extended sustained outage due to extreme weather conditions.

Currently, Roddickton plant constitutes two portable diesel generators with about 1700 kW capacity. In case of emergency and long sustained outages in the GNP area, these portable generators can be used, as needed, to restore the essential supply of the affected communities in the region.

6.5 Options Associated with Standby Generation

There are several options available to address the present situation. Acres is of the opinion that an improved response time of the generation presently at Roddickton will improve the customer perceived quality of service. Three (3) scenarios have been identified with order of magnitude installation costs. This section is concluded with a summary and recommendation.

All of these options have been developed on a conceptual basis, and no site visits or detail design activities have been carried out in support of these assessments. All indicated costs are order of magnitude estimates based on other installations.

6.5.1 Option 1 – Local Operator at Roddickton

This is the present method (status quo) of operation. The operator has been trained to start up the generators when asked for by the control center. This person lives in Roddickton and it is mandatory for him to respond to the control center call within 30 minutes to start the generators for power delivery.

For the current situation at Roddickton, Hydro's operation and maintenance (O/M) costs are shown in the following table.

Equipment	2000	2001	2002	Total
Unit 229	$ 5,809	$ 4,913	$ 11,101	$ 21,823
Unit 2003	$ 2,010	$ 7,633	$ 52,604	$ 62,247
Totals	$ 7,819	$ 12,546	$ 63,705	$ 84,070

The above table shows an average plant maintenance cost of $28,000/year. For plant operation, the cost for the operator from Sept 2000 to Sept 2002 was $64,324 or $32,000/year. Hydro indicated that this retainer arrangement would continue, unless there is some change in the requirement for diesel generation at this delivery point. So for continued manual operation at Roddickton in the existing manner, the total operation and maintenance costs are approximately $28,000 + $32,000 or $60,000/year.

6.5.2 Option 2 – Relocating Generation to St. Anthony

This option involves moving the 2 x 850 kW units from Roddickton to St. Anthony. One of the units is transportable. That is, it is in a container with no wheels. The other unit is a trailer unit with wheels that can be towed to the other site. This transportable and a trailer unit similar to the one at Roddickton were once installed at St Anthony prior to 1999.

The relocation work involves minor site preparation at St Anthony, draining and securing the units at Roddickton; transport using cranes and floats; off loading, and connecting at St Anthony. Tie-in points on the St Anthony bus are still in place so these units can be reconnected easily. The transportable unit has a full PLC based controller that can be connected to the St Anthony automatic load management systems and be fully remote controlled from ECC in St John's the same as the St Anthony plant. The trailer unit has only an electronic governor and manual synchronizer. But there is a permanent fulltime operator at St Anthony this unit can be operated manually under direction from Hydro's Energy Control Centre. There should be no need for the added expense of remote control.

The estimated costs for relocating the two units to St. Anthony are:

Transport and Installation at St Anthony	$ 46,000
Electrical & Control Equipment Purchase & Installation	$ 18,500
Commissioning	$ 8,500
Engineering & Project Management	$ 8,400
Total	$ 81,400

If the units were relocated to St. Anthony the fuel costs will likely remain unchanged. The Roddickton operator costs of $32,000/year would be eliminated and the maintenance costs of $28,000/year would be reduced. Since the Hydro maintenance staff is headquartered at St. Anthony, the maintenance of the Roddickton units included costs for travel and expenses would be eliminated, which are about 25% of the costs. So by relocating the two diesels to St. Anthony, the maintenance costs would be reduced to about $21,000/year. Hence, by relocating the two diesels to St Anthony, the average yearly savings in operation and maintenance costs is estimated at $39,000/year.

Relocating the units to St Anthony would cost approximately $82,000 and yield an average yearly saving of $39,000.

6.5.3 Option 3 – Remote Control Operation of Roddickton

As stated above, the transportable unit has a PLC controller and can be remote controlled from the power line carrier system to the Roddickton terminal station. The trailer unit has to be fitted with a PLC and rewired in order for it to be remote controlled. As well, the RTU at Roddicton is an older type RTU that has only six(6) spare control points. It would require 12 points for each unit for remote control. The RTU would therefore have to be replaced, as part of the work.

The estimated costs for remote control of both units at Roddickton are:

Supply, Install & Commission Replacement RTU	$ 71,000
Electrical & Control Equipment Purchase	$ 37,000
Installation & Commissioning	$ 8,000
Engineering & Project Management	$ 13,700
Total	$129,700

Remote control of the units at Roddickton would cost approximately $130,000 and the average yearly maintenance cost would be approximately $28,000. The contract operator would not be required.

6.5.4 Feasible and Recommended Option

At present there is a trained person to operate the generation at Roddickton on an intermittent basis but should something technically go wrong, may require a utility crew to visit the site. This would delay the startup and reduce the supply performance for the customers. The synchronization times to BES network at present are also on average 50 minutes longer than at St. Anthony.

The most costly option appears to be adding remote control at Roddickton for the standby generation. This is primarily due to some technical challenges in automating the second unit and providing the necessary control and data channels required.

Finally, moving of the 2 x 850 kW units from Roddickton to St. Anthony provides benefits in reduced operating and maintenance costs. There is some risk if the TL257 would start showing average or below average reliability, but fulltime crews are available at St. Anthony, which should mitigate the more likely generator failure than a transmission line outage.

It is therefore recommended that the generation be moved from Roddickton to St. Anthony, as it is the lowest cost solution, it provides better service to the customers at Roddickton, and it will have anticipated lower maintenance costs because of the close proximity of the maintenance crews.

7. Conclusions and Recommendations

7 Conclusions and Recommendations

A top down approach was used to analyze the delivery point and transmission line performance statistics. The conclusions are grouped in Section 7.1 using the same approach:

- Overall Reliability Performance – a high level review of the SAIDI, SAIFI statistics within Hydro and in comparison to other utilities.
- Primary Causes of Interruptions– A closer look at how each delivery point was affected by the various outages. Using CEA classifications, events are classified by their primary cause.
- Underlying Causes of Interruptions– This reviews the root cause of an event, to the point that some general statements can be made about what type of solution may be effective to reduce further occurrences of this type of event.
- Reliability Performance Comparison with Other Utilities
- Sustainable Delivery Point Performance
- Standby Generation Performance – A review of the generation performance and usage over the last 6 years, including a recommendation on how to improve customer delivery point performance.

Finally, the recommendations of the report are summarized in section 7.2.

7.1 Conclusions

Overall Reliability Performance

The review and analysis of six-year reliability performance of six delivery points in the GNP north area revealed the following:

The SAIDI indices show that the average duration of interruptions for each delivery point is in the typical acceptable range, as found in the electric supply industry.

The SAIFI-SI index (frequency of sustained interruptions) for all the delivery points has become more acceptable in the recent years. However, the SAIFI-MI indexes (frequency of momentary interruptions) as well as the composite SAIFI (SI+MI) indexes for momentary and sustained interruptions are higher than the range of values generally acceptable in the utility industry.

Primary Causes of Interruptions

The primary cause analysis revealed that the biggest contributors to total customer interruption time in the GNP north area were:

- Defective equipment at Plum Point Substation (distribution recloser malfunctions caused transmission equipment protection to operate)
- Adverse weather on TL239
- Defective equipment on TL 221 (faulty insulator)
- Adverse environment on TL226
- Defective equipment at Bear Cove Station (Corrosion on gas pressure relay connector)
- Defective equipment on TL 259 (broken cross arm during storm conditions)
- Adverse weather on TL241
- Adverse weather on TL221
- Human Element at Plum Point Substation

The most prevalent primary cause for total customer interruption time was defective equipment at 39.6% (major causes being Plum Point and Bear Cove stations, and TL221 & TL259 lines). The second most prevalent causes are adverse weather and system conditions with 30.4% (major causes being TL239, TL241 and TL221 lines) and 11.9 % respectively. Overall in the GNP North area, 53.1% of customer outage time was attributable to the transmission lines and other equipment related outage time was 46.9%.

St. Anthony was the least impacted delivery point in terms of total outage time but it experienced the highest number of customer interruption minutes, amounting to 25%. Main Brook was the least impacted in terms of customer minutes.

The primary cause analysis on interruption frequency showed that the major causes for customer interruptions were:

- Adverse weather on TL241
- Adverse weather on TL239
- Adverse weather on TL259
- Defective equipment on TL259 (Jumper contacting cross arm)
- Adverse weather on TL221
- Adverse weather on TL244
- Adverse weather on TL227

The three 138 kV line sections TL241, TL239 and TL259 contributed to more than 66% of the total customer outage occurrences. Overall in the GNP North area, about 93% occurrences are transmission related and only 7% are attributable to other equipment and unknown causes.

St. Anthony customers experienced the highest number of customer interruption occurrences at 34.1%

Underlying Causes of Interruptions

The dominant underlying causes of interruptions were as follows:

- Lightning on TL241 impacting all the delivery points
- High winds on TL239 impacting all the delivery points
- Defective equipment on TL259 impacting all the delivery points (Jumper contacting cross arm)
- High winds on TL227 but impacted mainly Hawkes Bay out of six delivery points monitored.
- High winds on TL221 but impacted Hawkes Bay only

Historically, adverse weather has been the major cause of interruptions on the GNP transmission system and is likely to remain the main cause of interruptions in future. The analysis of six-year data also revealed that most of the weather related interruptions occurred during 1998 and 1999 but the yearly interruption count has decreased in the last three years. This is partly attributable to the replacement of insulators on TL239, TL 226 and TL 227 circuits during 1999 and 2000.

Reliability Performance Comparison with Other Utilities

The SAIDI values for the GNP North area compares favorably with overall Hydro statistics for other radial lines and these values are also quite low in comparison to the statistics of the other utilities used in the study and the CEA averages.

The frequency of interruptions (SAIFI index values) in the GNP North area is the highest among the sample compared, as the delivery points in the GNP region are served by a significantly longer radial circuit among all compared.

Except TL259, all the other GNP area transmission circuits outperformed in terms of average annual interruption duration in comparison to the circuits belonging to other utilities and in comparison to the CEA average for similar types of circuits. The relatively poor statistics of TL259 are driven by an event of about 7 hours outage due to a broken cross arm during storm conditions.

Sustainable Delivery Point Performance

The sustainable delivery point performance in the GNP area is expected to be as follows:

- SAIDI $\leqslant$ 3.5 hr/year
- SAIFI – SI $\leqslant$ 6 occ/year
- SAIFI – MI $\leqslant$ 15 occ/year

Standby Generation Performance

The standby generation at Hawkes Bay contributed merely 12% of the time in relation to the total unplanned outage time. This low contribution is chiefly attributable to unavailability of the units due to control problems within the plant or at the Hawkes Bay station. At the same time, the standby generation at St. Anthony reduced the total outage duration of this delivery point by more than half. The standby generation at Roddickton took a longer time to start, and its contribution to reduce the total outage time was only about 22%. This reduced contribution of Roddickton standby generation is attributable to either the unavailability of the units, delayed local response time or the required generation being supplied from St. Anthony.

If the standby generation were removed, St. Anthony delivery point would experience the highest reliability impact, as the average duration of interruption would increase by more than 100%. Similarly, reliability performance of Main Brook and Roddickton delivery points would deteriorate significantly with the removal of standby generation from Roddickton. However, as per the past experience with standby generation at Hawkes Bay, the impact on delivery point reliability performance is not that significant. At the same time, it is worthwhile to mention that these reliability indices are well within the minimum performance standards followed in other parts of the country.

Based on the current load forecast and assuming that 25% of the load at each delivery point is essential load, it may be concluded that existing standby capacity should be sufficient and no additional generation will be required in the near future. If any additional generation were to be considered, portable generation would provide the greatest benefits.

In regard to the options considered for standby generation at Roddickton, the least cost and preferred solution is to move the two diesel units from Roddickton to St. Anthony.

7.2 Recommendations

In reviewing the delivery point and transmission line performance, the majority of the events have been attributed to either adverse weather or defective equipment.

Accordingly, the following is recommended in order to reduce the number of outages in future:

- Proactively maintain the protection and control equipment at stations serving the GNP North area to reduce sustained interruption times.
- Review the lightning statistics and identify locations on TL241 where shield wires or lightning arresters might be installed to reduce momentary interruptions on this long section of the 138 kV circuit.
- Identify the most exposed sections of circuits TL227, TL221 and TL239 to high winds, and implement corrective measures: for example, applying phase spacers or structure rebuilds to reduce the probability of phase slapping.

With respect to these recommendations, Hydro has been proactive and some corrective actions had already been taken by the time this study was commissioned. Hydro is using its FALLS lightning analysis software to study lightning activity on the GNP and assist in the identification of performance improvement initiatives. Furthermore, in 1999 and 2000/01, TL 239 and TL 227 were partially re-insulated and structures modified in the most exposed areas to eliminate salt contamination and line slapping problems. These efforts should continue, so that the impact to customer outage statistics is further reduced.

Furthermore, in reviewing customer delivery point performance in relation to standby generation contribution, in particular the duration of interruptions in GNP north area, it is recommended that:

- The generation be moved from Roddickton to St. Anthony, as it is the lowest cost solution, it provides better service to the customers at Roddickton, and it will have anticipated lower maintenance costs because of the close proximity of the maintenance crews.

Appendix A Definitions

Definitions

Reliability Statistics

Momentary Interruption (MI) - Any loss of supply voltage to a DP that has a duration of less than one minute. These are interruptions generally restored by automatic reclosure facilities, which are of very short duration (of the order of a few seconds). For computation purposes Momentary Interruptions are assigned zero duration.

Sustained Interruption (SI) - Any loss of supply voltage to a DP that has a duration of one minute or more. *In addition to the Sustained Interruption Frequency, the Interruption Duration of both the BES Supply Voltage and the Customer Load are reported* Generally, the loss of supply voltage to a DP will result in all Customer Load to be interrupted since most Canadian utilities have distribution systems that are supplied from a radial DP. However, there may be some situations where Customer Load is not interrupted or is restored sooner than the BES Supply Voltage, such as where a distribution system is operated as a meshed network or where there is an alternative BES Supply Voltage path.

System Average Interruption Frequency Index – Sustained Interruptions (SAIFI-SI) A measure of the average number of sustained interruptions that a customer experiences during a given period, usually one year.

SAIFI – System Average Interruption Frequency Index (Sustained Interruptions)

$$= \frac{\text{Total Number of Customer Interruptions}}{\text{Total Number of Customers Served}}$$

System Average Interruption Duration Index (SAIDI) - A measure of the average total interruption duration that a customer experiences during a given period, usually one year.

SAIDI – System Average Interruption Duration Index (Sustained Interruptions)

$$= \frac{\text{Sum of Customer Interruption Durations}}{\text{Total Number of Customers Served}}$$

Customer Average Interruption Duration Index (CAIDI) - A measure of the average total interruption duration that a customer experiences during a given period, usually one year.

CAIDI – Customer Average Interruption Duration Index

$$= \frac{\text{Sum of Customer Interruption Durations}}{\text{Total Number of Customer Interruptions}}$$

Bulk Electricity System (BES) - The Bulk Electricity System is composed of the Power Resources, the Transmission System that includes busses, switching equipment and circuits of 50 kV and above, all transformers connected to those busses or circuits and the low side busses associated with these transformers. It does not include the Distribution System.

Single-Circuit Supplied Delivery Point (SC) - A DP supplied from the BES by one circuit whereby the interruption of that circuit will cause an interruption to the Delivery Point.

Distribution System - The Distribution System is composed of the sub-transmission circuits and equipment, the distribution stations, and the distribution circuits, which deliver power from the BES to the ultimate customers.

Transmission Equipment Reliability

Outage Frequency (per 100 kilometer-years for transmission lines) – is the number of forced outages divided by the number of kilometer-years and which is in turn divided by 100.

Average Outage Duration or Mean Duration (hours) – is the total forced outage time divided by the number of forced outages.

Causes of Transmission Equipment Forced Outages

Defective Equipment - includes deterioration due to age; incorrect manufacturing design, materials and assembly; and lack of maintenance.

Adverse Weather - consists of lightning, rain, freezing rain, ice, snow, wind, high ambient temperature, low ambient temperature, freezing fog or frost and tornadoes.

Adverse Environment - includes salt spray, industrial pollution, humidity, corrosion, vibration, fire and flooding.

System Conditions - are high voltage, low voltage switching transient, overcurrent, high frequency, and low frequency.

Human Element - can be incorrect system records or diagrams; incorrect use of equipment; incorrect construction, installation or maintenance; incorrect protection setting; switching error; testing; incorrect circuit labeling; and deliberate or accidental damage by employees or utility contractors.

Foreign Interference - is any contact, deliberate or accidental damage or interference by persons (other than employees or utility contractors), vehicles, animals, trees or solar magnetic induction.

Appendix B Hydro One Delivery Point Performance Information

Customer Delivery Point Performance Standards

April 2002

hydro one

Customer Delivery Point Performance Standards

Hydro One Networks Inc.

In accordance with Section 2.5 of the Transmission System Code, Hydro One Networks Inc. (Networks) is required to develop performance standards at the customer delivery point level, consistent with system wide standards, that reflect:

- typical transmission-system configurations that take into account the historical development of the transmission system at the customer delivery point level;
- historical performance at the customer delivery point level;
- acceptable bands of performance at the customer delivery point level for the transmission system configurations; geographic area, load, and capacity levels; and
- defined triggers that would initiate technical and financial evaluations by the transmitter and its customers regarding performance standards at the customer delivery point level, exemptions from such standards, and study triggers and results.

The Customer Delivery Point Performance Standards and Triggers that are proposed for Networks' transmission system are shown in Table 1 below. Customer/Stakeholder feedback was solicited and their input incorporated, as appropriate, prior to finalizing these delivery point performance standards for submission to the OEB.

Performance Measure	Delivery Point Performance Standards *(Based on a Delivery Point's Total Average Station Load)*							
	0-15 MW		**15-40 MW**		**40-80 MW**		**>80 MW**	
	Standard (Average Performance)	Minimum Standard of Performance	Standard (Average Performance)	Minimum Standard of Performance	Standard (Average Performance)	Minimum Standard of Performance	Standard (Average Performance)	Minimum Standard of Performance
DP Frequency of Interruptions (Outages/yr)	4.1	**9.0**	1.1	**3.5**	0.5	**1.5**	0.3	**1.0**
DP Interruption Duration (min/yr)	89	**360**	22	**140**	11	**55**	5	**25**

Table 1: Networks' Delivery Point Performance Standards

These delivery point performance standards are based on rigorous statistical analysis of the historical (1991-2000) performance as measured by the frequency and duration of outages that covers the impact of all momentary and sustained interruptions caused by forced outages, excluding force majeure events that are deemed appropriate to be excluded (e.g. 1998 Ice Storm, tornadoes, earthquakes, other acts of God and any other significant event having "excessive" impact on performance that is beyond the reasonable control of, and not a result of the fault or negligence of Networks).

The minimum standards of performance are to be used as triggers by Networks to initiate technical and financial evaluations with affected customers. These bands are to:

- accommodate normal year-to-year delivery point performance variations,
- limit the number of delivery points that are to be considered "outliers" to a manageable/affordable level,
- deliver a level of reliability that is commensurate with customer value,
- and direct/focus efforts for reliability improvements at the "worst" performing delivery points.

The proposed minimum performance standards correspond to a performance bandwidth designed to capture about 90% of all delivery point performance and leave about 10% of the delivery points to be classified as performance "outliers."

These performance standards will apply to all existing transmission load customers (including Customers that have signed a connection cost recovery agreement prior to market opening). For new or expanding customer loads, the delivery point performance requirements will be specified and paid for by the customer based on their connection needs and negotiated as part of the connection cost recovery agreement.

When the three year rolling average of delivery point performance falls below the minimum standard of performance or when delivery point customer(s) indicate that analysis is required, Networks will initiate technical and financial evaluations to assess remedies for improving reliability.

To encourage proceeding with only those reliability performance improvements that are technically and economically practical and to limit the subsidisation of reliability improvement costs by other pool customers, Networks' level of incremental investment for improving the performance of an "outlier" will be limited to the present value of three years worth of transformation and/or connection revenue[1] associated with that delivery point. Any funding shortfalls for improving delivery point reliability performance will be made up by affected delivery point customers in the form of a financial/capital contribution. Cost responsibility for these investments is to be consistent with the new Market Rules and the Transmission System Code. Affected delivery point customer(s) will be responsible for all the costs associated with any new/modified facilities required on facilities (lines and stations) they own. The financial

[1] *In the special case where a delivery point pays only network tariffs, line connection tariffs are to be used as proxy in the revenue calculation.*

contribution requirements and cost sharing arrangement are to be detailed in a connection cost recovery agreement to be signed with the affected customer(s), before any work to improve delivery point outlier performance begins.

Networks will negotiate timing, solution, cost sharing arrangement, and any other related matters with each customer wanting to proceed with the delivery point reliability performance improvements. The timing/schedule will consider customer impacts, nature of the remedial measures, equipment deliveries, Networks resource capabilities, other investment priorities, and outage/resource availability.

In addition to addressing these delivery point performance standards, Networks is committed to maintaining transmission system-wide reliability levels and to meeting any system-wide service quality indicators approved by the OEB.

Appendix C Reliability Statistics Compiled by CEA

For the Period January 1, 1996
to December 31, 2000

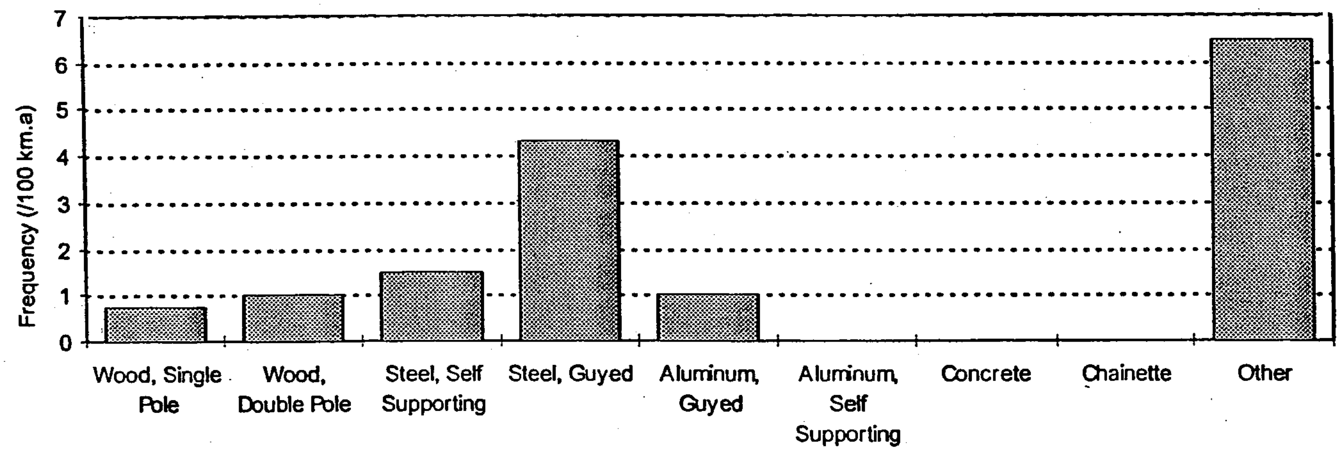
FORCED OUTAGE PERFORMANCE OF TRANSMISSION EQUIPMENT

Canadian Electricity
Association

MAY 2002

Prepared by:
Canadian Electricity Association

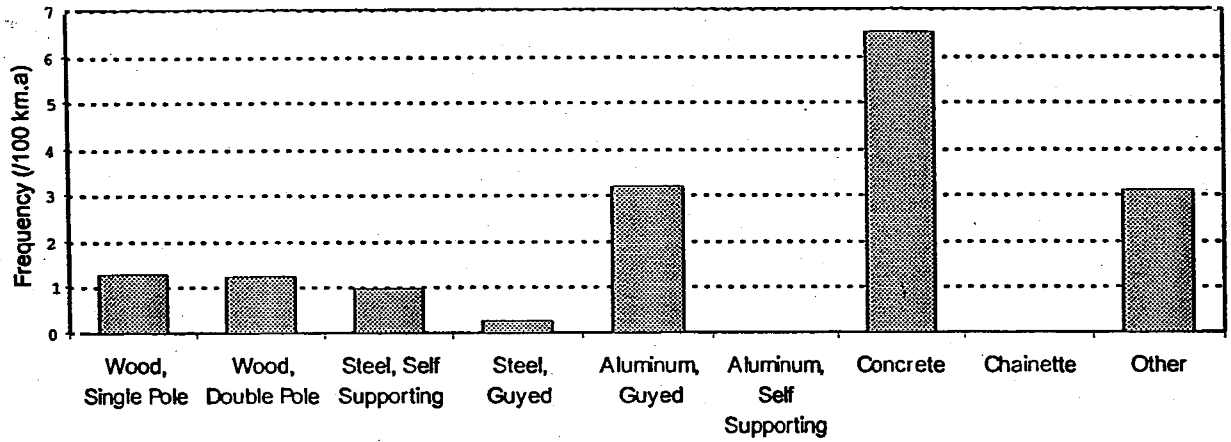
TRANSMISSION LINE ANALYSIS BY SUBCOMPONENT FOR LINE RELATED SUSTAINED FORCED OUTAGES



Frequency of line-related sustained forced outages of 110-149 kV transmission lines by supporting structure.

For Data Submitted By: All Canada
For the Period: 96-01 To 00-12
Voltage Classification: 110 - 149 kV

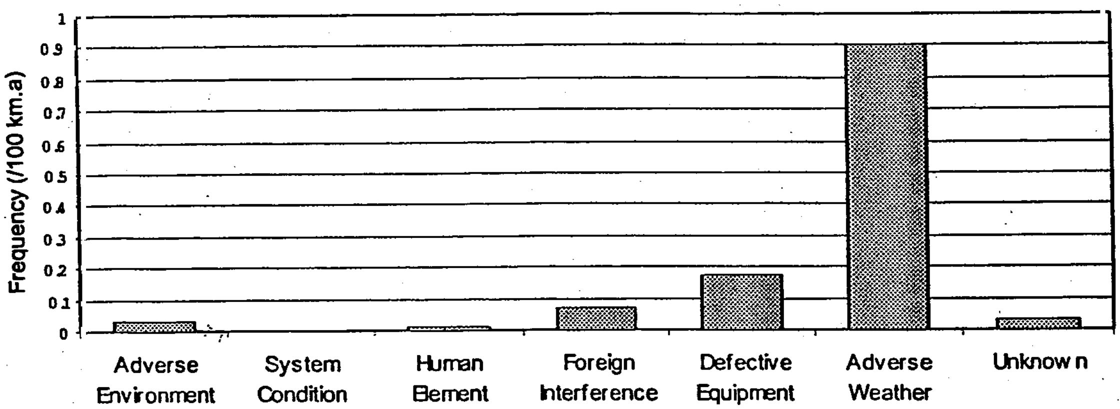
SUPPORTING STRUCTURE	KILOMETRE YEARS (km.a)	SUBCOMPONENT	NUMBER OF OUTAGES	FREQUENCY (PER 100 km.a)	TOTAL TIME (h)	MEAN DURATION (h)	MEDIAN DURATION (h)	UNAVAIL-ABILITY (%)
Wood, Single Pole	56,296	Structure	59	0.1048	3,218	54.5	10.37	0.065
		Joints And Dead-ends	0					
		Conductor	48	0.0853	737	15.4	4.97	0.015
		Insulation System	290	0.5151	3,231	11.1	0.18	0.065
		Ground Wire	11	0.0195	37	3.4	2.28	0.001
		Hardware	9	0.016	80	8.9	4.67	0.002
		Other	16	0.0284	210	13.1	0.82	0.004
		All Integral Subcomponents	433	0.7691	7,514	17.4	0.93	0.153
Wood, Double Pole	94,318	Structure	121	0.1283	6,388	52.8	11.83	0.077
		Joints And Dead-ends	2	0.0021	10	5	4.99	
		Conductor	77	0.0816	7,636	99.2	5.3	0.092
		Insulation System	703	0.7454	25,343	36	0.08	0.306
		Ground Wire	42	0.0445	313	7.5	0.39	0.004
		Hardware	11	0.0117	254	23.1	10.58	0.003
		Other	11	0.0117	387	35.1	3.72	0.005
		All Integral Subcomponents	967	1.0253	40,330	41.7	0.13	0.488
Steel, Self-Supporting	68,338	Structure	34	0.0498	11,782	346.5	10.35	0.197
		Joints And Dead-ends	10	0.0146	343	34.3	2.42	0.006
		Conductor	114	0.1668	1,020	9	0.13	0.017
		Insulation System	827	1.2102	18,049	21.8	0.07	0.301
		Ground Wire	15	0.0219	735	49	17.25	0.012
		Hardware	8	0.0117	82	10.2	7.09	0.001
		Other	5	0.0073	3	0.7	0.82	
		All Integral Subcomponents	1,013	1.4823	32,015	31.6	0.08	0.535



Frequency of line-related transient forced outages of 110-149 kV transmission lines by supporting structure.

For Data Submitted By: All Canada
For the Period: 96-01 To 00-12
Voltage Classification: 110 - 149 kV

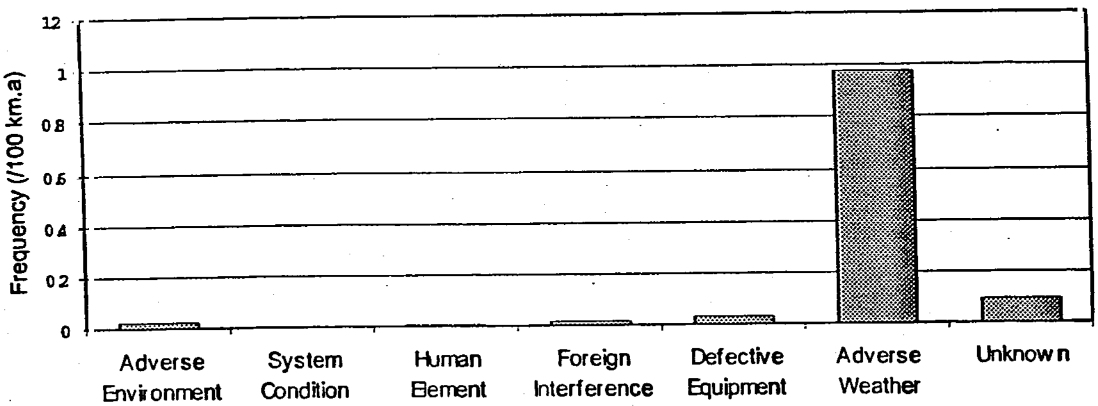
SUPPORTING STRUCTURE	KILOMETRE YEARS (km.a)	SUBCOMPONENT	NUMBER OF OUTAGES	FREQUENCY (PER 100 km.a)
Wood, Single Pole	56,296	Structure	14	0.0249
		Joints And Dead-ends	0	
		Conductor	52	0.0924
		Insulation System	628	1.1155
		Ground Wire	3	0.0053
		Hardware	1	0.0018
		Other	13	0.0231
		All Integral Subcomponents	711	1.263
Wood, Double Pole	94,318	Structure	5	0.0053
		Joints And Dead-ends	0	
		Conductor	21	0.0223
		Insulation System	1,117	1.1843
		Ground Wire	17	0.018
		Hardware	2	0.0021
		Other	10	0.0106
		All Integral Subcomponents	1,172	1.2426
Steel, Self-Supporting	68,338	Structure	1	0.0015
		Joints And Dead-ends	0	
		Conductor	9	0.0132
		Insulation System	661	0.9673
		Ground Wire	4	0.0059
		Hardware	0	
		Other	0	
		All Integral Subcomponents	675	0.9877



Frequency of line-related sustained forced outages of 110-149 kV transmission lines by primary cause.

For Data Submitted By: All Canada
For the Period: 96-01 To 00-12
Voltage Classification: 110 - 149 kV

SUPPORTING STRUCTURE	KILOMETRE YEARS (km.a)	PRIMARY CAUSE	NUMBER OF OUTAGES	FREQUENCY (PER 100 km.a)	TOTAL TIME (h)	MEAN DURATION (h)	MEDIAN DURATION (h)	UNAVAIL-ABILITY (%)
Wood, Single Pole	56,296	Defective Equipment	82	0.1457	2,361	28.8	7.56	0.048
		Adverse Weather	226	0.4014	4,047	17.9	0.1	0.082
		Adverse Environment	39	0.0693	284	7.3	2.97	0.006
		System Condition	3	0.0053	2	0.5	0.3	
		Human Element	9	0.016	60	6.7	1.18	0.001
		Foreign Interference	40	0.0711	659	16.5	4.98	0.013
		Unknown	34	0.0604	101	3	0.24	0.002
		All Primary Causes	433	0.7691	7,514	17.4	0.93	0.153
Wood, Double Pole	94,318	Defective Equipment	195	0.2067	12,357	63.4	6.57	0.15
		Adverse Weather	632	0.6701	26,922	42.6	0.07	0.326
		Adverse Environment	29	0.0307	156	5.4	0.15	0.002
		System Condition	1	0.0011		0.3	0.32	
		Human Element	10	0.0106	100	10	6.97	0.001
		Foreign Interference	83	0.088	726	8.8	3.1	0.009
		Unknown	17	0.018	68	4	0.13	0.001
		All Primary Causes	967	1.0253	40,330	41.7	0.13	0.488
Steel, Self-Supporting	68,338	Defective Equipment	102	0.1493	2,619	25.7	5.95	0.044
		Adverse Weather	856	1.2526	28,431	33.2	0.07	0.475
		Adverse Environment	8	0.0117	50	6.2	3.33	0.001
		System Condition	2	0.0029	35	17.5	17.54	0.001
		Human Element	5	0.0073	11	2.2	0.25	
		Foreign Interference	31	0.0454	838	27	0.52	0.014
		Unknown	9	0.0132	31	3.4	0.1	0.001
		All Primary Causes	1,013	1.4823	32,015	31.6	0.08	0.535



Frequency of line-related transient forced outages of 110-149 kV transmission lines by primary cause.

For Data Submitted By: All Canada
For The Period: 96-01 To 00-12
Voltage Classification: 110 - 149 kV

SUPPORTING STRUCTURE	KILOMETRE YEARS (km.a)	PRIMARY CAUSE	NUMBER OF OUTAGES	FREQUENCY (PER 100 km.a)
Wood, Single Pole	56,296	Defective Equipment	25	0.0444
		Adverse Weather	503	0.8935
		Adverse Environment	11	0.0195
		System Condition	1	0.0018
		Human Element	4	0.0071
		Foreign Interference	17	0.0302
		Unknown	150	0.2664
		All Primary Causes	711	1.263
Wood, Double Pole	94,318	Defective Equipment	32	0.0339
		Adverse Weather	1,024	1.0857
		Adverse Environment	41	0.0435
		System Condition	0	
		Human Element	10	0.0106
		Foreign Interference	22	0.0233
		Unknown	43	0.0456
		All Primary Causes	1,172	1.2426
Steel, Self-Supporting	68,338	Defective Equipment	11	0.0161
		Adverse Weather	635	0.9292
		Adverse Environment	3	0.0044
		System Condition	0	
		Human Element	0	
		Foreign Interference	5	0.0073
		Unknown	21	0.0307
		All Primary Causes	675	0.9877

Appendix D BES Delivery Point Statistics of Newfoundland and Labrador Hydro

printed: 07-May-03

Canadian Electrical Association

BES Delivery Point Interruptions

Newfoundland and Labrador Hydro

Delivery Point Interruption Data by: Region **From:** 06/01/1997 **To:** 05/31/1998

Show all (including momentary)
Customers : ALL
Unplanned Outages only

Delivery Point	Number of Interuptions		Interuption Duration (min)				Unsupplied Energy
	Momentary	Sustained	System Total	Supply Average	Customer Total	Load Average	MW Min
Region: Avalon Peninsula							
Come By Chance T1	0	2	32	16	1	0	16
Come By Chance T2	0	1	1	1	1	1	14
Hardwoods	0	2	74	37	74	37	13,604
Holyrood 38L	0	2	52	26	52	26	1,268
Holyrood 39L	0	1	9	9	9	9	216
Long Harbour	0	2	16	8	16	8	6
Oxen Pond	0	4	142	35	142	35	19,924
Western Avalon 64L	0	2	34	17	9	4	1,395
Western Avalon 86L	0	1	9	9	9	9	171
Total:	**0**	**17**	**369**	**22**	**313**	**18**	**36,614**
Region: Burin Peninsula							
Bay L'Argent	4	8	251	31	251	31	384
Linton Lake	4	8	559	70	182	23	1,610
Monkstown	4	2	391	195	391	195	200
Salt Pond	0	9	182	20	182	20	1,858
Total:	**12**	**27**	**1,383**	**51**	**1,006**	**37**	**4,052**
Region: Central							
Grand Falls F.C. T1	0	1	334	334	334	334	668
Grand Falls F.C. T2	0	4	256	64	256	64	5,068
Sunnyside - 100L	0	2	169	84	8	4	208
Sunnyside - 109L	0	2	169	84	8	4	216
Sunnyside - Rural	0	2	169	84	169	84	587
Total:	**0**	**11**	**1,097**	**100**	**775**	**70**	**6,747**

Delivery Point	Number of Interuptions: Momentary	Number of Interuptions: Sustained	Interuption Duration (min): System Total	Interuption Duration (min): Supply Average	Interuption Duration (min): Customer Total	Interuption Duration (min): Load Average	Unsupplied Energy MW Min
Region: Central South Coast							
Barachoix	1	5	3,684	737	3,684	737	11,799
Conne River	1	5	179	36	179	36	145
English Harbour West	1	5	3,684	737	3,684	737	5,899
Total:	**3**	**15**	**7,547**	**503**	**7,547**	**503**	**17,843**
Region: G.N.P.							
Bear Cove	11	7	566	81	566	81	1,426
Cow Head	5	2	8	4	8	4	7
Daniels Harbour	6	2	11	5	11	5	7
Glenburnie	0	13	155	12	155	12	93
Hawkes Bay	6	3	104	35	104	35	220
Main Brook	9	10	309	31	309	31	97
Parsons Pond	6	2	11	5	11	5	6
Plum Point	8	7	243	35	243	35	326
Rocky Harbour	0	12	96	8	96	8	91
Roddickton	9	10	333	33	275	27	407
St. Anthony	7	13	433	33	239	18	788
Wiltondale	0	13	155	12	155	12	14
Total:	**67**	**94**	**2,424**	**26**	**2,172**	**23**	**3,482**
Region: Labrador East							
Happy Valley Bus 12	0	8	1,670	209	392	49	15,219
Total:	**0**	**8**	**1,670**	**209**	**392**	**49**	**15,219**
Region: South West Coast							
Codroy	7	5	229	46	229	46	184
Port Aux Basques	7	5	257	51	71	14	485
Wheelers	0	1	26	26	0	0	0
Total:	**14**	**11**	**512**	**47**	**300**	**27**	**669**
Region: West Coast							
Stephenville	2	0	0	0	0	0	0
Stephenville Paper Mill	2	1	80	80	80	80	5,120
Total:	**4**	**1**	**80**	**80**	**80**	**80**	**5,120**

Delivery Point	Number of Interuptions Momentary	Sustained	Interuption Duration (min) System Total	Supply Average	Customer Total	Load Average	Unsupplied Energy MW Min
Region: West South Coast							
Burgeo	3	1	3	3	3	3	4
Hope Brook T1	10	2	6	3	6	3	32
Hope Brook T2	10	2	6	3	6	3	24
Total:	**23**	**5**	**15**	**3**	**15**	**3**	**60**
Region: White Bay							
Coney Arm	1	0	0	0	0	0	0
Hampden	1	0	0	0	0	0	0
Jacksons Arm	1	0	0	0	0	0	0
Total:	**3**	**0**	**0**	**0**	**0**	**0**	**0**
Grand Total:	**126**	**189**	**15,097**	**80**	**12,600**	**67**	**89,806**

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Canadian Electrical Association

BES Delivery Point Interruptions

Newfoundland and Labrador Hydro

Delivery Point Interruption Data by: ***Region*** **From:** 06/01/1998 **To:** 05/31/1999

Show all (including momentary)
Customers : ALL
Unplanned Outages only

	Number of Interuptions		*Interuption Duration (min)*				*Unsupplied Energy*
Delivery Point	Momentary	Sustained	System Total	Supply Average	Customer Total	Load Average	MW Min
Region: Avalon Peninsula							
Come By Chance T1	1	5	21	4	21	4	232
Come By Chance T2	1	7	25	4	25	4	202
Hardwoods	0	3	135	45	96	32	11,819
Holyrood 38L	0	4	243	61	142	35	1,569
Holyrood 39L	0	4	127	32	127	32	337
Long Harbour	0	4	1,862	465	1,862	465	372
Oxen Pond	0	4	149	37	118	29	14,258
Western Avalon 64L	1	4	75	19	75	19	6,786
Western Avalon 86L	1	4	135	34	135	34	2,311
Total:	**4**	**39**	**2,772**	**71**	**2,601**	**67**	**37,886**
Region: Burin Peninsula							
Bay L'Argent	5	5	55	11	55	11	83
Linton Lake	5	5	55	11	55	11	168
Monkstown	2	4	54	13	54	13	31
Salt Pond	4	7	58	8	58	8	785
Total:	**16**	**21**	**222**	**11**	**222**	**11**	**1,067**

Delivery Point	Number of Interuptions		Interuption Duration (min)				Unsupplied Energy
	Momentary	Sustained	System Total	Supply Average	Customer Total	Load Average	MW Min
Region: Central							
Grand Falls	0	1	250	250	0	0	120
Indian River 363L	1	1	2	2	2	2	10
South Brook	1	1	79	79	79	79	237
Springdale	1	0	0	0	0	0	0
Sunnyside - 100L	1	5	52	10	52	10	2,517
Sunnyside - 109L	1	5	54	11	54	11	2,908
Sunnyside - Rural	1	5	15	3	15	3	76
Total:	**6**	**18**	**452**	**25**	**202**	**11**	**5,868**
Region: Central South Coast							
Barachoix	0	2	2	1	2	1	5
Conne River	0	2	2	1	2	1	2
English Harbour West	0	2	2	1	2	1	2
Total:	**0**	**6**	**6**	**1**	**6**	**1**	**9**
Region: G.N.P.							
Bear Cove	17	2	55	27	55	27	110
Cow Head	18	1	26	26	26	26	36
Daniels Harbour	16	0	0	0	0	0	0
Glenburnie	0	4	4	1	4	1	3
Hawkes Bay	13	0	0	0	0	0	0
Main Brook	0	14	35	2	35	2	12
Parsons Pond	19	0	0	0	0	0	0
Plum Point	15	2	14	7	14	7	21
Rocky Harbour	0	4	4	1	4	1	6
Roddickton	0	14	35	2	35	2	53
St. Anthony	1	15	41	3	41	3	149
Wiltondale	0	4	4	1	4	1	1
Total:	**99**	**60**	**218**	**4**	**218**	**4**	**392**
Region: Labrador East							
Happy Valley Bus 12	0	2	2,152	1,076	420	210	4,791
Total:	**0**	**2**	**2,152**	**1,076**	**420**	**210**	**4,791**

Delivery Point	*Number of Interuptions* Momentary	Sustained	*Interuption Duration (min)* System Total	Supply Average	Customer Total	Load Average	*Unsupplied Energy* MW Min
Region: South West Coast							
Codroy	6	5	202	40	202	40	369
Port Aux Basques	6	5	214	43	218	43	2,756
Wheelers	0	1	1	1	1	1	0
Total:	**12**	**11**	**416**	**38**	**420**	**38**	**3,125**
Region: West Coast							
Stephenville	2	1	1	1	1	1	14
Stephenville Paper Mill	2	1	1	1	1	1	1
Total:	**4**	**2**	**2**	**1**	**2**	**1**	**15**
Region: West South Coast							
Burgeo	5	2	6	3	6	3	51
Hope Brook T1	7	2	2	1	2	1	0
Hope Brook T2	7	2	2	1	2	1	0
Total:	**19**	**6**	**10**	**2**	**10**	**2**	**51**
Region: White Bay							
Coney Arm	0	1	115	115	115	115	0
Hampden	0	1	115	115	115	115	35
Howley	0	1	115	115	115	115	23
Jacksons Arm	0	1	115	115	115	115	58
Total:	**0**	**4**	**460**	**115**	**460**	**115**	**116**
Grand Total:	**160**	**169**	**6,710**	**40**	**4,561**	**27**	**53,320**

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Canadian Electrical Association

BES Delivery Point Interruptions

Newfoundland and Labrador Hydro

Delivery Point Interruption Data by: Region   **From:** 06/01/1999   **To:** 05/31/2000

Show all (including momentary)
Customers : ALL
Unplanned Outages only

Delivery Point	*Number of Interuptions*		*Interuption Duration (min)*				*Unsupplied Energy*
	Momentary	Sustained	System Total	Supply Average	Customer Total	Load Average	MW Min
~~Region: Avalon Peninsula~~							
Western Avalon 64L	0	2	13	6	0	0	0
Total:	**0**	**2**	**13**	**6**	**0**	**0**	**0**
Region: Burin Peninsula							
Bay L'Argent	4	2	171	85	171	85	137
Linton Lake	3	1	170	170	170	170	221
Monkstown	4	2	171	85	171	85	52
Salt Pond	3	3	7	2	6	2	126
Total:	**14**	**8**	**519**	**65**	**518**	**65**	**536**
Region: Central							
Indian River 363L	1	0	0	0	0	0	0
Total:	**1**	**0**	**0**	**0**	**0**	**0**	**0**
Region: Central South Coast							
Barachoix	0	9	152	17	152	17	591
Conne River	0	9	152	17	152	17	189
English Harbour West	0	9	250	28	250	28	327
Total:	**0**	**27**	**554**	**21**	**554**	**21**	**1,107**

Delivery Point	Number of Interuptions		Interuption Duration (min)				Unsupplied Energy
	Momentary	Sustained	System Total	Supply Average	Customer Total	Load Average	MW Min
Region: G.N.P.							
Bear Cove	9	6	108	18	53	9	162
Cow Head	54	5	637	127	637	127	531
Daniels Harbour	19	4	540	135	540	135	252
Glenburnie	0	13	273	21	273	21	514
Hawkes Bay	41	4	441	110	315	79	1,200
Main Brook	0	15	141	9	86	6	40
Parsons Pond	47	5	750	150	750	150	207
Plum Point	9	5	107	21	107	21	119
Rocky Harbour	0	11	129	12	129	12	128
Roddickton	0	15	145	10	90	6	113
St. Anthony	1	14	162	12	85	6	440
Wiltondale	0	12	283	24	283	24	64
Total:	**180**	**109**	**3,716**	**34**	**3,348**	**31**	**3,769**
Region: Labrador East							
Happy Valley Bus 12	0	15	6,234	416	354	24	4,160
Total:	**0**	**15**	**6,234**	**416**	**354**	**24**	**4,160**
Region: South West Coast							
Codroy	18	1	690	690	622	622	978
Port Aux Basques	27	5	996	199	368	74	2,421
Total:	**45**	**6**	**1,686**	**281**	**990**	**165**	**3,399**
Region: West Coast							
Stephenville Paper Mill	1	0	0	0	0	0	0
Total:	**1**	**0**	**0**	**0**	**0**	**0**	**0**
Region: West South Coast							
Burgeo	3	0	0	0	0	0	0
Hope Brook T1	3	0	0	0	0	0	0
Hope Brook T2	2	0	0	0	0	0	0
Total:	**8**	**0**	**0**	**0**	**0**	**0**	**0**
Grand Total:	**249**	**167**	**12,722**	**76**	**5,764**	**35**	**12,971**

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Canadian Electrical Association

BES Delivery Point Interruptions

Newfoundland and Labrador Hydro

Delivery Point Interruption Data by: Region   **From:** 06/01/2000   **To:** 05/31/2001

Show all (including momentary)
Customers : ALL
Unplanned Outages only

Delivery Point	Number of Interuptions		Interuption Duration (min)				Unsupplied Energy
	Momentary	Sustained	System Total	Supply Average	Customer Total	Load Average	MW Min
~~Region: Avalon Peninsula~~							
Come By Chance T2	0	1	728	728	0	0	0
Holyrood 39L	0	1	4	4	0	0	0
Total:	**0**	**2**	**732**	**366**	**0**	**0**	**0**
Region: Burin Peninsula							
Bay L'Argent	17	5	441	88	441	88	1,335
Linton Lake	17	3	266	89	266	89	2,862
Monkstown	17	5	696	139	696	139	687
Salt Pond	3	0	0	0	0	0	0
Total:	**54**	**13**	**1,403**	**108**	**1,403**	**108**	**4,884**
Region: Central							
Indian River 363L	0	1	4	4	4	4	42
South Brook	0	1	492	492	492	492	2,460
Sunnyside - 100L	2	0	0	0	0	0	0
Total:	**2**	**2**	**496**	**248**	**496**	**248**	**2,502**
Region: Central South Coast							
Barachoix	0	9	789	88	789	88	2,623
Conne River	1	9	930	103	930	103	562
English Harbour West	1	9	737	82	737	82	689
St. Albans	0	1	13	13	13	13	14
Total:	**2**	**28**	**2,469**	**88**	**2,469**	**88**	**3,888**

Delivery Point	*Number of Interuptions* Momentary	Sustained	*Interuption Duration (min)* System Total	Supply Average	Customer Total	Load Average	*Unsupplied Energy* MW Min
Region: G.N.P.							
Bear Cove	26	10	47	5	47	5	49
Cow Head	2	1	8	8	8	8	6
Daniels Harbour	10	1	32	32	32	32	12
Glenburnie	0	5	126	25	126	25	35
Hawkes Bay	10	1	32	32	32	32	96
Main Brook	8	31	315	10	217	7	75
Parsons Pond	7	1	93	93	93	93	25
Plum Point	23	10	47	5	47	5	89
Rocky Harbour	0	5	108	22	108	22	162
Roddickton	7	31	317	10	230	7	385
St. Anthony	3	29	320	11	134	5	663
Wiltondale	0	5	126	25	126	25	35
Total:	**96**	**130**	**1,571**	**12**	**1,200**	**9**	**1,632**
Region: Labrador East							
Happy Valley Bus 12	1	12	2,252	188	335	28	4,059
Total:	**1**	**12**	**2,252**	**188**	**335**	**28**	**4,059**
Region: South West Coast							
Codroy	8	5	942	188	443	39	856
Port Aux Basques	9	6	1,004	167	190	32	1,689
Wheelers	0	1	5	5	5	5	0
Total:	**17**	**12**	**1,951**	**163**	**638**	**53**	**2,545**
Region: West Coast							
Stephenville	0	3	51	17	51	17	469
Stephenville Paper Mill	0	1	2	2	2	2	140
Total:	**0**	**4**	**53**	**13**	**53**	**13**	**609**
Region: West South Coast							
Burgeo	6	1	72	72	72	72	50
Hope Brook T1	7	2	73	36	73	36	9
Hope Brook T2	7	2	73	36	73	36	1
Total:	**20**	**5**	**218**	**44**	**218**	**44**	**60**

Delivery Point	Number of Interuptions		Interuption Duration (min)				Unsupplied Energy
	Momentary	Sustained	System Total	Supply Average	Customer Total	Load Average	MW Min
Region: White Bay							
Coney Arm	0	1	1	1	1	1	0
Hampden	0	1	1	1	1	1	1
Jacksons Arm	0	1	1	1	1	1	1
Total:	0	3	3	1	3	1	2
Grand Total:	192	211	11,148	53	6,815	32	20,181

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Canadian Electrical Association

BES Delivery Point Interruptions

Newfoundland and Labrador Hydro

Delivery Point Interruption Data by: Region   **From:** 06/01/2001   **To:** 05/31/2002

Show all (including momentary)
Customers : ALL
Unplanned Outages only

Delivery Point	Number of Interuptions		Interuption Duration (min)				Unsupplied Energy
	Momentary	Sustained	System Total	Supply Average	Customer Total	Load Average	MW Min
Region: Avalon Peninsula							
Hardwoods	0	1	3	3	4	4	299
Holyrood 38L	0	1	3	3	3	3	17
Holyrood 39L	0	1	3	3	3	3	93
Oxen Pond	0	1	6	6	7	7	767
Total:	**0**	**4**	**15**	**4**	**17**	**4**	**1,176**
Region: Burin Peninsula							
Bay L'Argent	3	0	0	0	0	0	0
Monkstown	3	0	0	0	0	0	0
Salt Pond	0	1	1,179	1,179	0	0	0
Total:	**6**	**1**	**1,179**	**1,179**	**0**	**0**	**0**
Region: Central							
Deer Lake Plant	0	1	5	5	0	0	0
Deer Lake TL-225	0	1	4	4	4	4	24
Grand Falls F.C. T1	0	1	10	10	0	0	0
Grand Falls F.C. T2	0	1	10	10	0	0	0
South Brook	2	0	0	0	0	0	0
Total:	**2**	**4**	**29**	**7**	**4**	**1**	**24**
Region: Central South Coast							
Barachoix	0	2	115	57	115	57	372
Conne River	0	2	2	1	2	1	2
English Harbour West	0	2	2	1	2	1	2
Total:	**0**	**6**	**119**	**20**	**119**	**20**	**376**

Delivery Point	Number of Interuptions		Interuption Duration (min)				Unsupplied Energy
	Momentary	Sustained	System Total	Supply Average	Customer Total	Load Average	MW Min
Region: G.N.P.							
Bear Cove	8	3	322	107	326	109	595
Cow Head	1	1	5	5	5	5	6
Daniels Harbour	3	1	14	14	14	14	11
Glenburnie	1	11	27	2	27	2	21
Hawkes Bay	4	2	350	175	350	175	736
Main Brook	6	5	113	23	113	23	30
Parsons Pond	4	0	0	0	0	0	0
Plum Point	6	3	341	114	363	121	490
Rocky Harbour	1	11	27	2	27	2	60
Roddickton	6	5	190	38	218	44	436
St. Anthony	6	5	30	6	48	10	184
Wiltondale	1	11	27	2	27	2	21
Total:	**47**	**58**	**1,446**	**25**	**1,518**	**26**	**2,590**
Region: Labrador East							
Happy Valley Bus 12	0	6	56	9	56	9	824
Total:	**0**	**6**	**56**	**9**	**56**	**9**	**824**
Region: South West Coast							
Codroy	49	5	165	33	165	33	364
Port Aux Basques	49	5	167	33	111	22	1,493
Wheelers	0	2	238	119	238	119	0
Total:	**98**	**12**	**570**	**47**	**514**	**43**	**1,857**
Region: West Coast							
Stephenville	0	1	59	59	59	59	2,027
Stephenville Paper Mill	0	1	67	67	67	67	4,739
Total:	**0**	**2**	**126**	**63**	**126**	**63**	**6,766**
Region: West South Coast							
Burgeo	6	3	69	23	69	23	9
Hope Brook T1	10	3	70	23	70	23	25
Hope Brook T2	10	3	70	23	70	23	12
Total:	**26**	**9**	**209**	**23**	**209**	**23**	**46**

Delivery Point	*Number of Interuptions* Momentary	Sustained	*Interuption Duration (min)* System Total	Supply Average	Customer Total	Load Average	*Unsupplied Energy* MW Min
Region: White Bay							
Coney Arm	0	1	659	659	659	659	1
Hampden	0	1	659	659	659	659	517
Jacksons Arm	0	1	659	659	659	659	317
Total:	**0**	**3**	**1,977**	**659**	**1,977**	**659**	**835**
Grand Total:	**179**	**105**	**5,726**	**55**	**4,540**	**43**	**14,494**

printed: 07-May-03

Canadian Electrical Association

BES Delivery Point Interruptions

Newfoundland and Labrador Hydro

Delivery Point Interruption Data by: Region   **From:** 06/01/2001   **To:** 05/31/2002

Show all (including momentary)
Customers : ALL
Unplanned Outages only

Delivery Point	*Number of Interuptions*		*Interuption Duration (min)*				*Unsupplied Energy*
	Momentary	Sustained	System Total	Supply Average	Customer Total	Load Average	MW Min
Region: Avalon Peninsula							
Hardwoods	0	1	3	3	4	4	299
Holyrood 38L	0	1	3	3	3	3	17
Holyrood 39L	0	1	3	3	3	3	93
Oxen Pond	0	1	6	6	7	7	767
Total:	**0**	**4**	**15**	**4**	**17**	**4**	**1,176**
Region: Burin Peninsula							
Bay L'Argent	3	0	0	0	0	0	0
Monkstown	3	0	0	0	0	0	0
Salt Pond	0	1	1,179	1,179	0	0	0
Total:	**6**	**1**	**1,179**	**1,179**	**0**	**0**	**0**
Region: Central							
Deer Lake Plant	0	1	5	5	0	0	0
Deer Lake TL-225	0	1	4	4	4	4	24
Grand Falls F.C. T1	0	1	10	10	0	0	0
Grand Falls F.C. T2	0	1	10	10	0	0	0
South Brook	2	0	0	0	0	0	0
Total:	**2**	**4**	**29**	**7**	**4**	**1**	**24**
Region: Central South Coast							
Barachoix	0	2	115	57	115	57	372
Conne River	0	2	2	1	2	1	2
English Harbour West	0	2	2	1	2	1	2
Total:	**0**	**6**	**119**	**20**	**119**	**20**	**376**

Delivery Point	Number of Interuptions		Interuption Duration (min)				Unsupplied Energy
	Momentary	Sustained	System Total	Supply Average	Customer Total	Load Average	MW Min
Region: G.N.P.							
Bear Cove	8	3	322	107	326	109	595
Cow Head	1	1	5	5	5	5	6
Daniels Harbour	3	1	14	14	14	14	11
Glenburnie	1	11	27	2	27	2	21
Hawkes Bay	4	2	350	175	350	175	736
Main Brook	6	5	113	23	113	23	30
Parsons Pond	4	0	0	0	0	0	0
Plum Point	6	3	341	114	363	121	490
Rocky Harbour	1	11	27	2	27	2	60
Roddickton	6	5	190	38	218	44	436
St. Anthony	6	5	30	6	48	10	184
Wiltondale	1	11	27	2	27	2	21
Total:	**47**	**58**	**1,446**	**25**	**1,518**	**26**	**2,590**
Region: Labrador East							
Happy Valley Bus 12	0	6	56	9	56	9	824
Total:	**0**	**6**	**56**	**9**	**56**	**9**	**824**
Region: South West Coast							
Codroy	49	5	165	33	165	33	364
Port Aux Basques	49	5	167	33	111	22	1,493
Wheelers	0	2	238	119	238	119	0
Total:	**98**	**12**	**570**	**47**	**514**	**43**	**1,857**
Region: West Coast							
Stephenville	0	1	59	59	59	59	2,027
Stephenville Paper Mill	0	1	67	67	67	67	4,739
Total:	**0**	**2**	**126**	**63**	**126**	**63**	**6,766**
Region: West South Coast							
Burgeo	6	3	69	23	69	23	9
Hope Brook T1	10	3	70	23	70	23	25
Hope Brook T2	10	3	70	23	70	23	12
Total:	**26**	**9**	**209**	**23**	**209**	**23**	**46**

	Number of Interuptions		Interuption Duration (min)				Unsupplied Energy
Delivery Point	Momentary	Sustained	System Total	Supply Average	Customer Total	Load Average	MW Min
Region: White Bay							
Coney Arm	0	1	659	659	659	659	1
Hampden	0	1	659	659	659	659	517
Jacksons Arm	0	1	659	659	659	659	317
Total:	**0**	**3**	**1,977**	**659**	**1,977**	**659**	**835**
Grand Total:	**179**	**105**	**5,726**	**55**	**4,540**	**43**	**14,494**

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Canadian Electrical Association

BES Delivery Point Interruptions

Newfoundland and Labrador Hydro

Delivery Point Interruption Data by: *Region* **From:** 06/01/2002 **To:** 05/31/2003

Show all (including momentary)
Customers : ALL
Unplanned Outages only

Delivery Point	Number of Interuptions		Interuption Duration (min)				Unsupplied Energy
	Momentary	Sustained	System Total	Supply Average	Customer Total	Load Average	MW Min
Region: Avalon Peninsula							
Come By Chance T2	2	1	1	1	1	1	12
Hardwoods	0	3	22	7	62	21	15,238
Holyrood 38L	0	1	120	120	120	120	2,844
Holyrood 39L	0	1	4	4	0	0	0
Long Harbour	1	1	720	720	720	720	10
Oxen Pond	0	3	81	27	110	37	18,806
Western Avalon 64L	0	1	270	270	0	0	0
Western Avalon 86L	0	1	272	272	0	0	0
Total:	3	12	1,490	124	1,013	84	36,910
Region: Burin Peninsula							
Bay L'Argent	16	0	0	0	0	0	0
Linton Lake	8	0	0	0	0	0	0
Monkstown	16	0	0	0	0	0	0
Salt Pond	6	1	4	4	0	0	0
Total:	46	1	4	4	0	0	0
Region: Central							
Buchans	0	1	51	51	51	51	72
Deer Lake Plant	0	2	102	51	0	0	0
Deer Lake TL-225	0	2	102	51	102	51	1,338
Grand Falls F.C. T1	0	1	80	80	0	0	0
Grand Falls F.C. T2	0	1	80	80	0	0	0
South Brook	19	2	12	6	12	6	60
Total:	19	9	427	47	165	18	1,470

Delivery Point	Number of Interuptions		Interuption Duration (min)				Unsupplied Energy
	Momentary	Sustained	System Total	Supply Average	Customer Total	Load Average	MW Min
Region: Central South Coast							
Barachoix	2	0	0	0	0	0	0
Conne River	2	0	0	0	0	0	0
English Harbour West	2	0	0	0	0	0	0
Total:	**6**	**0**	**0**	**0**	**0**	**0**	**0**
Region: G.N.P.							
Bear Cove	24	5	236	47	236	47	648
Cow Head	24	3	191	64	191	64	270
Daniels Harbour	22	4	195	49	195	49	92
Glenburnie	0	4	100	25	100	25	57
Hawkes Bay	22	5	210	42	196	39	1,018
Main Brook	26	6	303	50	189	31	63
Parsons Pond	23	4	195	49	195	49	105
Plum Point	24	5	234	47	234	47	571
Rocky Harbour	1	4	100	25	100	25	477
Roddickton	26	6	308	51	225	37	424
St. Anthony	20	6	309	51	127	21	476
Wiltondale	0	4	100	25	100	25	57
Total:	**212**	**56**	**2,481**	**44**	**2,088**	**37**	**4,257**
Region: Labrador East							
Happy Valley Bus 12	0	8	19	2	21	3	471
Total:	**0**	**8**	**19**	**2**	**21**	**3**	**471**
Region: South West Coast							
Codroy	7	2	82	41	82	41	243
Port Aux Basques	28	3	83	28	83	28	1,621
Wheelers	0	1	79	79	79	79	0
Total:	**35**	**6**	**244**	**41**	**244**	**41**	**1,864**

Delivery Point	Number of Interuptions		Interuption Duration (min)				Unsupplied Energy
	Momentary	Sustained	System Total	Supply Average	Customer Total	Load Average	MW Min
Region: West Coast							
Massey Drive Bus 2 and 3	0	1	55	55	55	55	3,696
Massey Drive Bus 4	0	2	490	245	490	245	12,304
Stephenville	1	1	91	91	91	91	3,640
Stephenville Paper Mill	1	1	91	91	91	91	6,370
Total:	**2**	**5**	**727**	**145**	**727**	**145**	**26,010**
Region: West South Coast							
Burgeo	16	5	1,791	358	1,791	358	4,368
Hope Brook T1	20	5	1,426	285	1,426	285	344
Hope Brook T2	20	5	1,426	285	1,426	285	344
Total:	**56**	**15**	**4,643**	**310**	**4,643**	**310**	**5,057**
Region: White Bay							
Coney Arm	3	1	57	57	57	57	0
Hampden	3	1	57	57	57	57	43
Howley	0	1	57	57	57	57	23
Jacksons Arm	3	1	57	57	57	57	71
Total:	**9**	**4**	**228**	**57**	**228**	**57**	**137**
Grand Total:	**388**	**116**	**10,263**	**88**	**9,129**	**79**	**76,176**

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Canadian Electrical Association

BES Delivery Point Interruptions

Newfoundland and Labrador Hydro

Delivery Point Interruption Data by: **Region** **From:** 06/01/2003 **To:** 05/31/2004

Show all (including momentary)
Customers : ALL
Unplanned Outages only

	Number of Interuptions		*Interuption Duration (min)*				*Unsupplied Energy*
Delivery Point	Momentary	Sustained	System Total	Supply Average	Customer Total	Load Average	MW Min
Region: 0							
0	0	0	0	0	0	0	0
Total:	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Grand Total:	**0**	**0**	**0**	**0**	**0**	**0**	**0**