Board Order No. P.U. 3(2014)
Investigation and Hearing into Supply Issues and Power Outages on the Island Interconnected System

NEWFOUNDLAND AND LABRADOR HYDRO

A Review of Supply Disruptions and Rotating Outages: January 2-8, 2014 Volume I

March 24, 2014

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EXECUTIVE SUMMARY

Background

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

On January 4, 2014, an unrelated event involving the failure and destruction by fire of a 230 kV transformer at the Sunnyside terminal station resulted in a wide disruption of power supply to the Avalon Peninsula and other areas. This event, and the failure of individual 230 kV breakers at Sunnyside and other locations, set in motion a series of transmission system and generation events that extended the need for rotating outages through to January 8, 2014. Overall, Hydro's system responded to events as designed and expected and protected against more serious equipment damage and the possibility of more frequent or extended outages.

The impact of these events on customers across the island was significant and extensive. With this in mind, and consistent with the organization's focus on continuous improvement, Hydro initiated an internal review of these supply disruptions and outages immediately following system restoration on January 10, 2014. The primary purpose of this review was to identify any actions, conditions or other factors that contributed to these disruptions and outages, and to identify immediate and longer-term actions required to prevent similar events from occurring in the future.

Another important purpose of this review was to identify what went well in Hydro's response to these events and in the efforts made to restore service as safely and as quickly as possible, to enable sharing and learning across Hydro and with other organizations.

Hydro's internal review was structured to be both expeditious and comprehensive. A framework was developed to guide this review and ensure that all appropriate areas of investigation were covered. Teams were formed to review all aspects of Hydro's performance in the areas of load forecasting; generation planning; asset management; generation availability; transmission availability; emergency response and restoration; communication and coordination with customers; and technology and communications infrastructure. Internal reviews were supplemented by the use of external consultants, with significant experience in electric utility operations, to provide independent, expert reviews and opinions. The external reviews completed for Hydro are noted below:

1. **Ventyx, an ABB company** (Ventyx)-- (Load Forecasting and Generation Planning)
2. **AMEC Americas Limited** (AMEC)-- Brian Scott (Transmission Availability)
3. **Henville Consulting Inc**. (Henville Consulting) – Charles Henville (Protection & Control Impacts)
4. **AMEC Americas Limited** – Blair Seckington (Asset Management Strategy and Practices)

In addition, Hydro contracted Mr. Brian Tink, a certified Taproot Process Matter Expert, and former employee of Ontario Power Generation, to facilitate Hydro's root cause analysis of various transmission system events.

Key Findings

Overall, the comprehensive reviews completed by internal teams and independent reviewers confirmed that Hydro's operations and processes are consistent with industry standards, and in some cases they are best practice.

The design of Hydro's transmission network follows industry practices and provides a reliable and robust network. AMEC's review highlighted that the performance of Hydro's bulk transmission system compares favorably with Canadian Electricity Association (CEA) averages. Henville Consulting noted that, while Hydro's transmissions lines and system transformers were operating in many unusual conditions and with unusual system stress during the January 4 and

5, 2014 events, most of the protection systems responded appropriately to problems with primary equipment during the restoration process.

The majority of Hydro's asset base is between 35 and 40 years old, and requires increasing attention for maintenance, refurbishment and replacement. Hydro recognized and addressed this reality in 2006 and began taking measures to complete detailed condition assessments of its key assets. A comprehensive asset management program was implemented in 2009, which has resulted in a significantly expanded asset refurbishment and replacement program and associated capital expenditures. This "cradle to grave" approach to ensuring asset health and reliability has been a focus for Hydro since 2006, and steady progress has been made in making sure Hydro's asset management program is embedded in all aspects of its operations. This was acknowledged by AMEC in their review.

Ventyx confirmed that Hydro's load forecasting processes are consistent with accepted utility standards and are effective in enabling Hydro to reliably forecast and plan for the electricity needs of the province. Ventyx verified that Hydro's generation planning process conforms with industry norms and practices. Ventyx also identified possible opportunities for incremental improvement in the areas of load forecasting and generation planning.

The availability and performance of Hydro's hydroelectric and oil-fired thermal generating assets has been consistent with, or better than, Canadian industry averages. Last year (2013) was a notable exception because of the failure of Unit 1 at Holyrood and the extended repair period that followed.

Hydro's internal review highlighted some specific issues that contributed to the supply disruptions and outages, and these have been identified for immediate priority attention. In addition, the internal review also identified some suggestions that, although not contributing to these outages, nevertheless would be useful improvements. These too are being implemented. In most cases action has already been taken or is in progress.

Hydro's emergency response and system restoration efforts were carried out safely and efficiently.

Key Actions

Gas Turbines

The Hardwoods and Stephenville gas turbines were largely unavailable leading up to, and during, the January 2 to 8, 2014 period. The reliability of these generation assets is planned to improve and be closer to industry standards going forward as a result of the significant upgrade and maintenance work performed on these units over the last 12 to 18 months, as well as the additional planned work required to complete these overhauls. However, Hydro's review identified further actions beyond those already incorporated into existing plans, including a review of gas turbine maintenance practices and addressing the root causes of repeat failure events.

A further action by Hydro has been the creation of a new Manager level position reporting to the Vice President responsible for Hydro, who will be specifically accountable for all aspects of asset management and plant reliability for Hydro's combustion turbine and diesel powered generating facilities.

230 kV Breakers

Hydro has a multi-year breaker replacement program that it has been executing according to plan. However, the prevalence of breaker failures during the events of January 4 and 5, 2014 and January 2013, coupled with the age and maintenance-intensive nature of this terminal station equipment, has resulted in Hydro further evaluating its existing breaker replacement and refurbishment program to mitigate against future failures of these key components. AMEC recommended that Hydro accelerate its breaker replacement program, and Hydro agrees with this. In addition, Hydro intends to review the maintenance program for these breakers, including the maintenance cycle standard, to identify any changes required to help ensure maximum reliability.

Critical Spares

The de-rating of Unit 3 at Holyrood (from 150 MW to 50 MW) due to the failure of a forced draft (FD) fan motor was a key aspect of generation unavailability leading into January 2 and 3, 2014. Although the FD fan motor was repaired and replaced expeditiously, it highlights the need to continuously review Hydro's critical spares program. A great deal of work has been done by Hydro and its Critical Spares Council to improve and integrate its critical spares strategy throughout the organization, and this work continues. However, Hydro believes, as recommended by AMEC, that it should continue the ongoing review of its critical spares philosophy for Holyrood and its other generation assets, incorporating this latest experience.

Generation Planning

Ventyx confirmed that Hydro's generation planning process conforms with industry standards. They also identified an opportunity to improve Hydro's generation planning going forward by integrating expanded sensitivity testing in its generation planning model. Hydro has previously identified the need to add new generation capacity in 2015, and sensitivity testing recommended by Ventyx will be incorporated into Hydro's current ongoing analysis of the options and preferred strategy to validate the size and timing of the optimum capacity addition from a cost and reliability perspective. This will be incorporated into the planned capacity deficit submission to the Board of Commissioners of Public Utilities (PUB) in early April, 2014.

Other key findings, recommendations and actions are identified in the remainder of this Report.

Acknowledgements

Over the period January 2 to 8, 2014 there were significant and widespread outages on Hydro's Island Interconnected System. Hydro understands the significance of the impact of these events on customers, and is committed to restoring customer confidence in the provincial power delivery system.

Hydro also acknowledges the efforts and commitment of its employees and other organizations in responding to the events of January 2 to 8, 2014. Unplanned and unexpected system occurrences involving two unrelated series of events posed a significant challenge for Hydro and its employees in restoring operations in several different locations across Hydro's system, often in hazardous and challenging weather conditions. In the circumstances, emergency response and restoration activities were carried out effectively and as quickly as possible – and most importantly, safely.

1 INTRODUCTION

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

On January 4, 2014 an unrelated event involving the failure and destruction by fire of a 230 kV transformer at the Sunnyside terminal station resulted in a wide disruption of power supply to the Avalon Peninsula and other areas. This event, and the failure of some 230 kV breakers at Sunnyside terminal station, Western Avalon terminal station, and the Holyrood switchyard, set in motion a series of transmission system and generation facility events that added to the need for rotating outages through to January 8, 2014. While the impact on customers and the general public was significant and extended, Hydro's system responded as designed and expected and protected against more serious equipment damage and the possibility of more frequent or extended outages.

Hydro understands the significance of these events on customers, and immediately following the return of normal supply Hydro initiated a comprehensive internal review of these supply disruptions and outages on January 10, 2014. This review examined all relevant areas of Hydro's operations. The review involved internal investigation teams as well as external consultants who were engaged to independently review specific elements of Hydro's planning and forecasting processes, asset management program and transmission system performance.

The primary purpose of this review was to identify any actions, conditions or other factors that contributed to these disruptions and outages, and to identify both the immediate and longer-term actions required to correct these and prevent similar events from occurring in the future. Later sections of this Report summarize the events in more detail, and Schedules 1 and 2 of this

Report provide a detailed overview of the sequence of events that led up to the events of January 2 and 3, 2014 and then the unrelated events which occurred at Sunnyside.

The key findings of Hydro's internal review, and the key and high priority actions that are required, are identified in these later sections as well. In the meantime, at a very high level, two key findings were as follows:

1. The inability of Hydro to meet the full system load experienced on January 2 and 3, 2014 was essentially related to the unavailability of sufficient generation supply. In particular, several unplanned generation outages in the last half of December 2013, involving five different generating facilities, resulted in a supply deficit of 233 MW at the end of December 2013. Very cold temperatures in early January 2014 that were sustained over several days, combined with the additional holiday season system load and other factors, resulted in a supply shortage that initiated the first series of outages on January 2, 2014.
2. The supply disruptions and outages that occurred on January 4, 2014, and the days that followed, were initiated by the failure of a transformer, followed almost instantly by a breaker failure, the sequential combination of which led to a total loss of the transformer at the Sunnyside terminal station. This was followed by another transformer failure at the Western Avalon terminal station and another breaker failure in the Holyrood switchyard. These transmission system events extended the outages that first occurred on January 2 and 3, 2014, however the underlying causes were unrelated to the generation supply issues outlined in 1) above.

Section 2 describes the review process used by Hydro, and the areas that were included for analysis and investigation.

Section 3 provides background about Hydro and its operations, its regulatory environment and its organizational structure.

Section 4 briefly reviews Hydro's winter readiness in terms of system availability and operational readiness prior to the events in early January 2014.

Section 5 of this Report reviews the above events in reference to Hydro's areas of investigation, summarizes the findings, and identifies actions required.

Section 6 reviews Hydro's winter supply plan for the remainder of the 2014 winter, and through to 2017, when the Muskrat Falls generating facility and the Labrador Island Link are scheduled to be brought on line and integrated into the provincial power system.

2 REVIEW PROCESS

2.1 Analysis Framework

Hydro's internal review was structured to be both expeditious and broad in nature. Hydro's primary goal was to quickly identify, and where possible, act on any conditions or factors that caused or contributed to the supply shortages and outages that occurred in January 2014.

Consistent with prudent industry practice, a comprehensive framework was developed to guide this review and ensure that all appropriate areas of investigation were covered. Teams were formed to review Hydro's performance in the following eight focus areas:

1. Load forecasting
2. Generation and Reserve planning
3. Asset management strategy and practices
4. Generation availability
5. Transmission availability
6. Emergency response and restoration
7. Coordination and communication with customers
8. Technology and communications infrastructure

Guidance was provided to internal teams regarding the component areas of each of the above that should be included within the scope of their respective reviews. These component areas are noted below.

1. Load Forecasting
    a) Performance during the events
    b) Underlying assumptions and related risk of error
    c) Communication between Planning and Operations
    d) Overall integrity of the forecasting methodology
2. Generation and Reserve Planning
    a) Planning performance leading up to and during the events
    b) Reliability criteria and operating assumptions
    c) Risk profile as operating load forecasts increase over time
    d) Options for incremental generation
3. Asset Management Strategy and Practices
    a) Asset Management strategy and standards
    b) Maintenance execution
    c) Long Term Asset Plans
    d) Critical spares strategy
    e) Councils of Experts
4. Generation Availability
    a) Gas turbine availability
    b) Holyrood availability
    c) Hydro generation availability
    d) Wind generation availability
5. Transmission Availability
    a) Transmission performance
    b) Breakers and Terminal stations
    c) Protection and Control response

6. <u>Emergency Response and Restoration</u>
   a) Emergency preparedness
   b) Emergency response
   c) System restoration
7. <u>Coordination and Communication With Customers</u>
   a) Communication and outage coordination with Newfoundland Power
   b) Capacity assistance from Corner Brook Pulp and Paper
   c) Communication with general public and Hydro customers
   d) Call for Customer conservation
8. <u>Technology and Communications Infrastructure</u>
   a) Energy Management System
   b) Computer and telecommunications network and devices

Teams were advised not to be limited by these guidelines, and to consider other aspects of their focus areas they felt could be relevant to their review of potential contributing factors. From a corrective standpoint, teams were asked to focus on identifying and addressing any conditions or factors that could be determined to have caused, or contributed to, the supply disruptions and outages.

Internal focus area reports were completed, and are available as schedules to this Report, for each of the focus areas. In the area of Transmission Availability, the focus area report is supplemented by a root cause report and a report on Hydro's protection system. The Ventyx report can be found as an Appendix to each of the Load Forecasting and Generation and Reserve Planning reports.

2.2 External Resources

While Hydro relied primarily on internal resources to complete this review, Hydro also made extensive use of independent external experts. These included Blair Seckington and Brian Scott of AMEC, and Charles Henville of Henville Consulting, all of whom produced independent reviews of Hydro's asset management strategy and practices (Seckington) and various aspects of transmission system performance at Hydro (Scott and Henville). All of these individuals have extensive utility industry experience in Canada and other parts of the world, and are qualified to provide an objective and informed perspective on the areas they were asked to review. More detail regarding the scope of their reviews, and their backgrounds and credentials, are available in the responses provided by Hydro to PUB Requests for Information (RFIs) in February, 2014 (see PUB-NLH-075).

Mr. Brian Tink, an external TapRooT® Process Matter Expert, facilitated the work of the multi-disciplinary team[1] (that included OEM representatives as well) that was assembled to complete structured root cause analyses[2] of four key transmission and terminal station equipment failures that occurred on January 4 and 5, 2014:

1. Sunnyside Terminal Station T1 transformer failure;
2. Sunnyside Terminal Station 230 kV bus lockout;
3. Western Avalon Terminal Station T5 transformer lockout; and
4. B1L17 circuit breaker failure in the Holyrood Switchyard.

Hydro also engaged Ventyx, an ABB company, to complete an independent review of its load forecasting and generation planning processes. Ventyx are recognized experts who provide consulting services to energy companies in the areas of integrated resource planning, resource evaluation and planning, and other related areas. The Ventyx final report was received by Hydro on March 20, 2014.

The independent reports completed for Hydro are noted below, and are also available as Schedules to this Report.

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[1] See PUB-NLH-075 for further details regarding the composition of this team.
[2] Hydro used the TapRooT® process, a systematic and structured process for identifying causal factors and associated root causes that are linked to events such equipment failures.

1. **Ventyx, an ABB company** -- (Load Forecasting and Generation Planning)
2. **AMEC Americas Limited --** Brian Scott (Transmission Availability)
3. **Henville Consulting Inc**. – Charles Henville (Protection & Control Impacts)
4. **AMEC Americas Limited** – Blair Seckington (Asset Management Strategy and Practices)

2.3 Review Coordination and Oversight

Processes were established to ensure that Hydro's internal review was effectively coordinated and completed on a timely basis, and to ensure that the objectives of the review were achieved. The ongoing coordination of this review was the responsibility of an Executive Review Team, chaired by the Vice President of Human Resources and Organizational Effectiveness. The Vice President of Strategic Planning and Business Development and three senior managers from various parts of Nalcor Energy were the other members of this Review Team.

In addition to the Executive Review Team, an Events Analysis Steering Committee was established to provide overall, executive level, oversight to the review. This Committee had a broader composition, and included the President and CEO and other Vice Presidents of Nalcor Energy, with direct accountability for the areas being reviewed. Further detail regarding the composition of these teams and their purposes were included in an RFI response provided to the PUB by Hydro in February, 2014 (see PUB-NLH-078).

3 BACKGROUND

3.1 Scope of Operations

Hydro is the primary generator of electricity in Newfoundland and Labrador. The utility delivers safe, least-cost, reliable power to utility, industrial, residential and commercial customers throughout the province. Hydro's statutory mandate is indicated in Section 5(1) of the *Hydro Corporation Act,* SNL 2007, c.11-17 as follows:

"The objects of the corporation are to develop and purchase power on an economic and efficient basis … and to supply power, at rates consistent with sound financial administration, for domestic, commercial, industrial or other uses in the province …"

Hydro's electricity generation activities involve the operation of nine hydroelectric generating stations, one oil-fired plant, three gas turbines and 25 diesel plants. Transmission, distribution and customer service activities include the operation and maintenance of over 3,700 kilometres of transmission lines, as well as 3,300 kilometres of distribution lines. Hydro serves over 36,000 direct residential and commercial customers, Newfoundland Power, as well as industrial customers that include Corner Brook Pulp and Paper, North Atlantic Refining, Vale, Praxair, and Teck Resources Ltd.

Hydro's current service areas include the Island Interconnected system, the Labrador Interconnected System, the L'Anse au Loup System and isolated diesel communities in Labrador and on the island. Customers served by the Island Interconnected system were impacted by the January 2014 events.

3.2 Generation and Transmission Infrastructure

The Island Interconnected System is primarily characterized by large hydroelectric generation capability located off the Avalon Peninsula with two parallel 230 kV lines bringing energy to the Avalon Peninsula where demand is concentrated, and a large oil-fired thermal generating plant on the Avalon Peninsula. Figure 3.1 below presents a visual overview of Hydro's generation and transmission infrastructure both on the island of Newfoundland and in Labrador.

FIGURE 3.1: Hydro's Generation and Transmission Infrastructure

As outlined in Table 1 below, over 60% of Hydro owned generation is hydroelectric. An additional 30% comes from the Holyrood Thermal Generating Station (HTGS). The balance is generated from gas turbine and diesel units.

TABLE 1: Island Interconnected System Generating Capacity (MW)

		Firm (Dependable)	Additional	Total
Newfoundland and Labrador Hydro				
Owned	Hydroelectric	927.3	-	927.3
Owned	Holyrood	465.5	-	465.5
Owned	Gas Turbine	100.0	-	100.0
Owned	Diesel	14.7	-	14.7
	Total	1,507.5	-	1,507.5
Purchased	Hydroelectric	78.0	31.8	109.8
Purchased	Co-Generation	8.0	7.0	15.0
Purchased	Wind	-	54.0	54.0
	Total	86.0	92.8	178.8
Total NLH System		1,593.5	92.8	1,686.3
Customer Owned				
Corner Brook Pulp and Paper	Hydroelectric	99.1	22.3	121.4
Newfoundland Power	Hydroelectric	78.7	18.2	96.9
Newfoundland Power	Gas Turbine	36.5	-	36.5
Newfoundland Power	Diesel	5.0	-	5.0
	Total	219.3	40.5	259.8
Total Island Interconnected System		1,812.8	133.3	1,946.1

Many of Hydro's key generating and transmission assets were installed in the late 1960s and the 1970s. Over half of the Island Interconnected system generating capacity comes from assets that are more than 40 years old. Transmission assets are aging as well, with over 50% of Hydro's transmission lines in service for more than 35 years.

In 2006, Hydro recognized the magnitude and potential impacts of its aging asset base and related customer reliability considerations. At that time, Hydro initiated a series of asset condition assessments and also began a review of maintenance practices. In 2009, a comprehensive, long-term asset management approach, consistent underlying organizational structures and processes, was developed and implemented throughout Hydro.

Over the last five years, formal condition assessments have been completed on many key assets and asset groups, and resulting recommendations have been integrated into 20, five and one year asset management plans and related capital plans. This planning has been a key factor in the more than two-fold growth in Hydro's capital expenditures since 2005, to secure the long-term reliability of the province's power system.

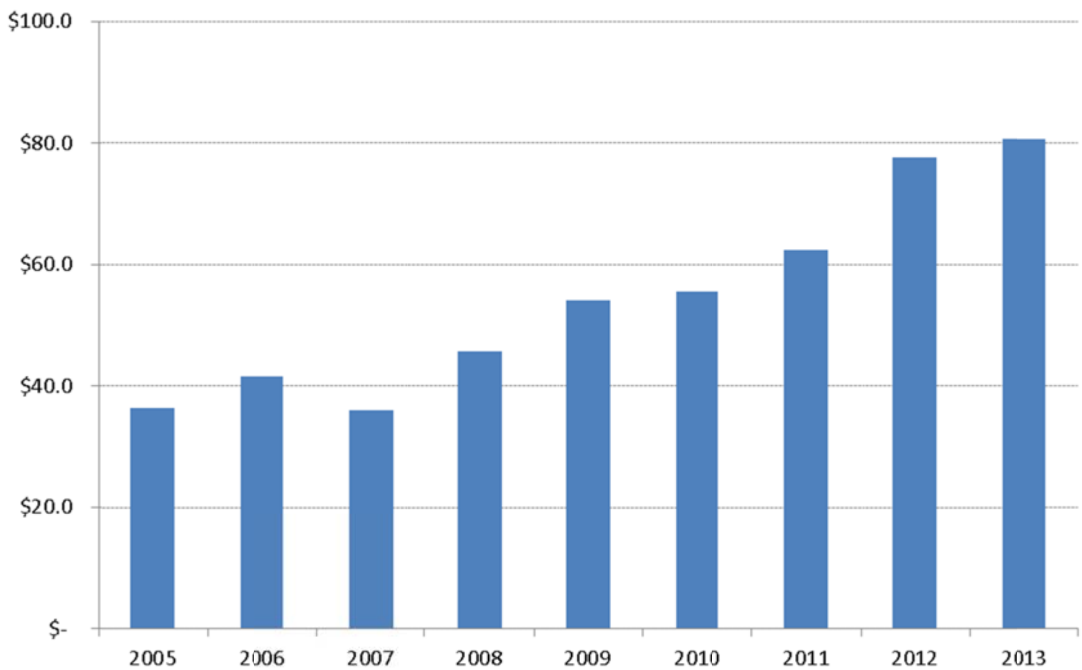


FIGURE 3.2: Capital Expenditures, Newfoundland & Labrador Hydro

2005-2013

3.3 Regulatory Context

Hydro is a regulated utility and is subject to the oversight of the PUB in relation to various aspects of its operations, including the approval of annual capital budgets and the electricity rates that are charged to all customer classes. The regulatory approval process for Hydro's capital plan and the compensation Hydro receives for its services, and the process for approving changes in its rates, are governed by Sections 41, 70(1) and 71 respectively of the *Public Utilities Act*, RSNL 1990, c. p-47.

41(1) A public utility shall submit an annual capital budget of proposed improvements or additions to its property to the board for its approval not later than December 15 in each year for the next calendar year, and the budget shall include an estimate of contributions toward the cost of improvements or additions to its property the public utility intends to demand from its customers.

(2) The budget shall contain an estimate of future required expenditures on improvements or additions to the property of the public utility that will not be completed in the next calendar year.

(3) A public utility shall not proceed with the construction, purchase or lease of improvements or additions to its property where

(a) the cost of the construction or purchase is in excess of $50,000; or

(b) the cost of the lease is in excess of $5,000 in a year of the lease

without the prior approval of the board.

70(1) A public utility shall not charge, demand, collect or receive compensation for a service performed by it whether for the public or under contract until the public utility has first submitted for the approval of the board a schedule of rates, tolls and charges and has obtained the approval of the board and the schedule of rates, tolls and charges so approved shall be filed with the board and shall be the only lawful rates, tolls and charges of the public utility, until altered, reduced or modified as provided in this Act.

71 A public utility shall submit for the approval of the board the rules and regulations which relate to its service, and amendments to them, and upon approval by the board they are the lawful rules and regulations of the public utility until altered or modified by order of the board.

Hydro is also governed by the *Electrical Power Control Act*, SNL 1994, c.E-S.1, which states, in part, in Section 3(b):

"It is declared to be the policy of the province that … all sources and facilities for the production, transmission and distribution of power in the province should be managed and operated in a manner … (i) that would result in the most efficient production, transmission and distribution of power, and … (iii) that would result in power being delivered to consumers in the province at the lowest possible cost consistent with reliable service …"

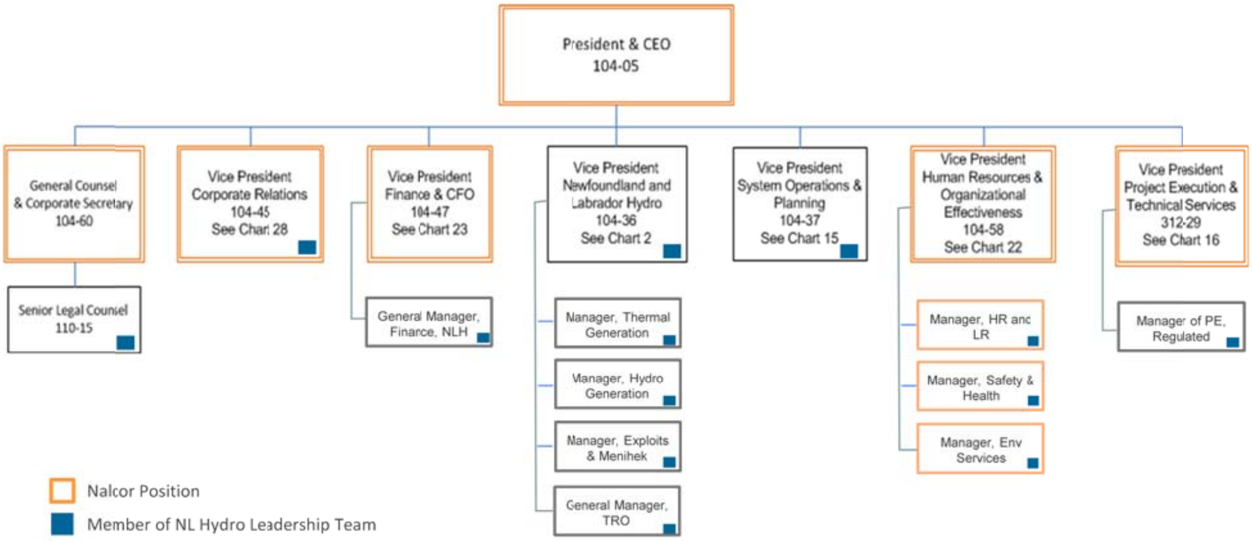
3.4 Organizational Structure

Hydro is a subsidiary of Nalcor Energy (Nalcor). Hydro operates independently of Nalcor's other lines of business, with a Vice President whose dedicated accountability is to manage Hydro's regulated operations in the safest and most efficient manner possible. While Hydro shares the same corporate goals as Nalcor and other Nalcor businesses, Hydro's corporate plan and the objectives, targets and performance metrics within it, are specific to Hydro and are linked directly to Hydro's business requirements. From a governance standpoint, Hydro's operations are overseen by its own Senior Leadership Team and its own separate Board of Directors.

Nalcor and its lines of business operate within a matrix organization design which enables Hydro to share functional support services across the various Nalcor entities. This approach was seen to be more beneficial for all of Nalcor's lines of business, and for Hydro in particular, from both an efficiency and cost-effectiveness standpoint. This approach has also enabled Hydro and all Nalcor lines of business to make the best use of the available people resources within Nalcor, many of whom work in areas that are highly specialized, and to leverage and transfer best practices from one area of Nalcor to others.

Figure 3.3 below presents the top level management structure for Hydro.

FIGURE 3.3
Hydro's Top Level Management Structure



To ensure that Hydro's corporate services requirements are appropriately supported, and to help ensure that Hydro's officers accountable for those areas are adequately informed and engaged in the business activities of Hydro, senior level positions are in place to provide dedicated support to Hydro. These include the following:

a) Corporate Controller
b) Human Resources/Labour Relations Lead
c) Safety & Health Lead, Electricity Operations
d) Manager, Project Execution (Regulated Operations)
e) Senior Communications Advisor

Evolution and Transition

Hydro's organizational structure has evolved and changed in response to its business requirements. In recent years, Hydro has moved through two significant organizational adjustments.

In 2009 and into 2010, Hydro implemented several organizational changes in support of its Asset Management Strategy (AMS). The organizational structure in all operating areas was standardized in relation to the key functions of long-term asset planning; short-term work scheduling; work execution (maintenance); and operations. Key position titles were also standardized. Another key change was the creation of a new General Manager for Transmission and Rural Operations (TRO) accountable to the Vice President of Hydro for all three TRO regions in the Province (Central, Northern, Labrador). This structural change has enabled a stronger degree of integration and standardization within the three TRO regions from both an operations and asset management standpoint.

Given the importance of engineering services related to capital planning, project execution, and technical support within Hydro's integrated AMS framework, a parallel review of Hydro's Engineering Services model was completed during this same period. A key result was the creation of a senior, dedicated Manager of Project Execution for Hydro. This single point of contact has resulted in a much more effective capital planning process in support of Hydro, as well as more effective delivery of project execution and technical support services.

A second stage of organizational change occurred early in 2013, shortly after the Muskrat Falls project was sanctioned in December, 2012. In April 2013, the System Operations and System Planning departments of Hydro were integrated into one division under the responsibility of a new Vice President for System Operations and Planning. This position is accountable to the President and CEO of Hydro for planning and coordinating the design and implementation of a Muskrat Falls/Maritime Link Ready for Operations (RFO) team, as well as Hydro's longer-term organization model for electricity operations and the associated organizational structure post Muskrat Falls in-service.

The integration of Muskrat Falls into the provincial and North American electricity grids will have further impacts on Hydro's organizational structure. Ensuring that all the necessary preparatory work is done, and that Hydro's model for long term electricity operations has been designed and tested in advance, will be critical to ensuring Hydro's seamless transition into a new mode of operations within an interconnected North American system.

4 WINTER READINESS

4.1 System Availability

The design and operation of the Island Interconnected System reflects the island of Newfoundland's environmental and weather conditions as well as an electricity demand peak that occurs during the winter period – December to March[3]. The system load pattern is a key factor in Hydro's outage management approach, which is to meet demand while making optimal use of hydroelectric resources, while minimizing the operation of Holyrood and other more expensive generating sources. Hydro's focus is ensuring the economic dispatch of resources for the benefit of customers. In turn, the demand pattern is a constraint on the scheduling of maintenance and overhaul and capital work on Hydro's electricity assets.

From an operations perspective, Hydro manages its generation resource availability, and schedules generation unit outages for maintenance, in such a way as to maintain a system contingency reserve within an (n-1) criterion. Generation assets are managed so that total load can be met in the event of an unplanned loss of Hydro's largest available generating unit. In this context, Hydro's annual plan is to complete all significant maintenance and capital project work by the end of November each year to ensure that electricity system assets are ready and available to meet winter season demands.

Following the January 11, 2013 outage event in Holyrood, Hydro completed a series of activities to assess and further ensure electricity system readiness in advance of the 2013-2014 winter season. In particular, Hydro engaged an external engineering consultant to complete a winter readiness review of the Holyrood generating station, and a number of terminal stations. Other actions taken included completing key winter readiness enhancements based on inspections by Hydro's insurance company; assessing preventive maintenance completion for generating and terminal stations and ensuring that high priority work was completed; and undertaking a boiler

[3] In five of the last ten years, peak demand was experienced in January; in three years winter peak occurred in February; and in two years peak occurred in December.

and high-pressure steam/water condition assessment at Holyrood to better assess operational and safety risks associated with those systems.

4.2 Operational Plan and Storm Readiness

In the event that a severe weather event is forecast, or there is a system problem that affects Hydro’s ability to meet system load, Hydro’s System Operations Energy Control Centre (ECC) issues an advisory to field operations staff concerning the adverse weather or potential generation shortfall and prepares for the event.

In addition, in a severe weather event, Hydro’s response includes any or all of the following activities, depending on the expected severity of the event:

Pre-event coordination call to coordinate response activities;

a) Enhanced staffing levels at ECC and other control rooms as needed;
b) Deployment of work crews to reduce response time in the event of an unplanned outage or equipment problems;
c) Additional inspections of equipment and vehicles (4WD trucks; snowmobiles, all-terrain vehicles and specialized vehicles) to ensure full functionality and full gas tanks;
d) Additional communication with on-call personnel to ensure readiness to respond if needed;
e) Scheduling of additional snow removal to ensure ongoing access to critical infrastructure during storm events; and/or
f) Test run of standby diesels and gas turbines.

Since the events of January 2014, Hydro has also implemented changes to operational plans in advance of severe weather, including the more frequent testing of standby generation and increased fuel inventory levels.

5 FINDINGS AND ACTIONS

5.1 Findings

This section outlines the key findings of Hydro's internal review. The reports prepared by internal teams and independent consultants as part of Hydro's review which are provided as schedules to this Report, present detailed information pertaining to Hydro's investigation of the supply disruptions and rotating outages in January 2014. These should be consulted for specific information regarding the events, the analysis that has been completed, and detailed findings and recommendations.

The sub-sections below are structured in the following format:

1. Overall Assessment
2. Relevant Background
3. Key Findings
4. Other Findings

5.1.1 *Load Forecasting*

Overall Assessment

Hydro's load forecasting processes are consistent with accepted utility standards and are effective in enabling Hydro to reliably forecast, and plan for, the electricity needs of the province. This was validated by Ventyx in their independent review completed in March 2014.

The Ventyx review also verified that Hydro's medium term and short-term 7 day operating load forecasts did not lead to decisions that contributed to the rotating outages on January 2 and 3, 2014. Hydro's inability to meet the full system load on these days was related to the unavailability of sufficient generation (i.e., power supply). The peak demand that was experienced was within the range of Hydro's winter peak forecast.

Relevant Background

Hydro's historical forecasts of winter peak demand over the period 2003-14 have consistently been greater than the actual peak. The winter of 2013-14 was an exception, but the variance between the peak load of 1,501 MW experienced on December 14, 2013, and Hydro's forecast of 2013-14 winter peak load (1,478 MW) was 2% and within the expected range of its load forecast.[4]

The 2013-14 winter period was not the norm in that the winter peak demand occurred sooner than usual, in mid December, and the temperatures experienced in the last half of December 2013, were more severe, and more sustained, than historical December weather patterns. Despite the December peak, Hydro was fully able to meet its load requirements at that time. Hydro's inability to meet its full load in early January 2014 was related to the unavailability of sufficient generation at that time. This was further exacerbated by other factors which increased load beyond what it otherwise would have been, including:

a) the cumulative load effect associated with cold weather that sustained itself over several days and during day time hours;
b) the incremental demand on the system associated with cold load pickup;
c) additional transmission line losses in the area of 30 to 40 MW associated with the higher than normal transmission load being served on the Avalon Peninsula from generation outside the Avalon Peninsula because of the unavailability of generation from Hardwoods and Holyrood; and
d) The extra load related to higher residential use during the holiday season (approximately 30 MW).

[4] The peak load numbers referenced here indicate Hydro's system load, i.e., the load served by Hydro's owned and operated assets and purchases, which excludes the loads served by Deer Lake Power and Corner Brook Pulp and Paper. Hydro's system load reflects a level of output from Newfoundland Power's generation, which is estimated annually by Newfoundland Power.

Key Findings

There were no factors related to load forecasting that resulted in decisions that initiated or contributed to the supply disruptions or rotating outages in January 2014. Ventyx verified that Hydro's load forecasting processes are consistent with utility industry standards and appropriate for their use.

Other Findings

Although there were no issues with respect to the load forecast which contributed to the January 2014 events, certain recommendations which may help Hydro make incremental improvements to its load forecasting process are presented below.

Ventyx recommended that enhancements be made to the medium term load forecasting model to incorporate sensitivity testing for alternative load forecasts related to different extreme weather scenarios. Hydro agrees and believes this will provide more information on the potential variability of this forecast.

Ventyx also recommended that forecasting model assumptions related to the penetration of electric heat and conversion from non-electricity heating sources require review and refinement. Hydro agrees, and will work with Newfoundland Power to ensure there is consistency on this point in the load forecasts that Newfoundland Power provides to Hydro, which represents the majority share of the province's residential customer base.

Hydro's short term seven day load forecasting program (Nostradamus) is highly sensitive to temperature data. Temperatures experienced in mid December 2013 and early January 2014 were highly atypical and therefore not well represented within the model's historic dataset. This resulted in short term daily forecasts that were not always well correlated with actual load. This had no impact on the January 2014 system events, but more accurate daily load forecasts could improve the prediction and communication of these outages to both internal and external stakeholders, including Newfoundland Power and the general public. Hydro is continuing to test a new version of its Nostradamus forecasting software with the objective of addressing this issue. If this is not successful, Hydro plans to investigate alternative models.

5.1.2 *Generation and Reserve Planning*

Overall Assessment

In their independent review, Ventyx verified that Hydro's generation planning process conforms to industry norms and practices. Ventyx concluded that Hydro's generation planning reserve criterion (a Loss of Load Hours (LOLH) of 2.8 hours per year) is prudent and consistent with standard industry practices; that Hydro's overall forecasting assumptions related to generation unit forced outage rates, a key input to generation planning, are consistent with industry standards; and that Hydro's resource planning process conforms to the basic structure of Ventyx's model.

Relevant Background

A key criterion used by Hydro for generation planning purposes, which is standard within the electric utility industry, is LOLH. This is a probability-based assessment of the level of unserved load at the time of peak demand, due to insufficient generation, based on a number of model inputs. LOLH is expressed as the total number of hours in a year this would be expected to occur. Hydro's LOLH standard is 2.8 hours per year. Implicit in a LOLH of 2.8 is a Loss of Load Probability (LOLP) equivalent to one day in five years, or 0.2 days per year.

Hydro reviews its generation requirements and the need for capacity additions on a periodic basis. This was most recently as done in 2012, and the analysis at that time indicated that new capacity would be required in 2015 in order to stay within the LOLH standard of 2.8 hours per year. A proposal to meet generation capacity requirements is in the final stages of internal approval, and will be submitted to the PUB in early April, 2014.

Key inputs into Hydro's generation planning model are the forced (unplanned) outage rates that are assumed for each of the Hydro's generating asset classes. The forced outage rates used by Hydro are based on the historical performance of Hydro's thermal, hydroelectric, and gas turbine generators. However, in view of the importance of generation forced outage rates in its generation planning model, and following recent generation events, Hydro believes a review of its current assumptions is warranted. This is an area that Ventyx was asked to evaluate during its review.

Key Findings

There were no factors related to generation planning that resulted in decisions that initiated or contributed to the supply disruptions or rotating outages in January, 2014.

Other Findings

Although there were no issues with respect to the generation planning which contributed to the January 2 and 3, 2014 events, certain recommendations which may help Hydro make incremental improvements to its generation planning process are presented below.

Ventyx concluded that, while the forced outage rates used by Hydro for its generation planning purposes are representative of historical performance and consistent with industry standards, Hydro should continue its practice of modelling with a more conservative estimate for forced outage rates on thermal units. Ventyx recommended that Hydro complete a sensitivity or "break even" analysis of the forced outage rates for its various generation classes, which would be useful in identifying the impact that variations in forced outage rates at either Holyrood, Bay d'Espoir or at the gas turbines would have on the overall system LOLH. Hydro agrees with this recommendation and intends to incorporate these assessments into its capital submission addressing the forecasted 2015 capacity deficit noted above.

Although Ventyx observed that, in prior studies, Hydro's sensitivity analysis has focused primarily on commodity and costing assumptions, Ventyx recommended that Hydro should incorporate a more formal risk assessment approach into its future generation planning by expanding this sensitivity analysis to include the impacts of factors such as extreme weather and possibly other base case input assumptions such as generation availability. Hydro agrees with this recommendation and will be incorporating an expanded generation planning risk sensitivity analysis into its capital submissions addressing the forecasted 2015 generation capacity deficit.

5.1.3 *Asset Management Strategy and Practices*

Overall Assessment

Hydro works within a comprehensive, documented framework for Asset Management. Within this framework, asset management is defined as: *"The comprehensive management of asset requirements -- planning, procurement, operations, maintenance and evaluation in terms of life extension or rehabilitation, replacement or retirement to achieve maximum value for the stakeholders based on the required standard of service to current and future generations. It is a holistic, cradle-to-grave lifecycle view on how we manage our assets"*.

This comprehensive, "cradle to grave" approach to ensuring asset health and reliability has been a focus for Hydro since 2006, and a formal framework was developed and implemented in 2009. Since then, Hydro has made measured and steady progress in making sure its asset management program is embedded in all aspects of its operations. This was acknowledged by AMEC in their independent review.

Relevant Background

Several processes enable and support Hydro's asset management strategy. Organizationally, clear lines of accountability are established to ensure clarity regarding asset ownership, and ownership of the component areas of long-term asset planning; short-term planning and work scheduling; maintenance work execution; and operations. A single point of contact interface which exists between Hydro's business units and Project Execution and Technical Services facilitates the conversion of long term asset plans into 20, five and one year capital plans, and the efficient execution of annual project plans in support of long term asset plans.

Asset condition assessments are a key element of Hydro's asset management approach as well, and serve as key inputs to the prioritization of capital work to ensure the ongoing care and timely renewal of Hydro's installed asset base. This practice is consistent with the Electric Power Research Institute's (EPRI) condition assessment standard for large generation facilities.

Key Findings

AMEC's comprehensive review of Hydro's asset management approach highlighted that Hydro's asset management program is a deliberate, rigorous process that emphasizes self-assessment and measurement to ensure continuous progress and improvement. AMEC's opinion was that it provides the basis for ensuring *"the management of the right work on the right assets at the right time"*. Using Hydro's condition assessment program as an illustration, AMEC noted that Hydro's asset management approach is consistent with best electric industry practices.

The generation and transmission capacity that will be added to the provincial electricity system in 2017 by the Muskrat Falls generating facility and Labrador-Island Link will enable the closure of the Holyrood Thermal Generating Station as a generation source by no later than 2020. During the course of their review of Hydro's asset management program, AMEC were asked to specifically assess the operational integrity of Holyrood's long term asset plan in the context of Hydro's end of life plan for that facility. AMEC concluded that operations and maintenance programs at Holyrood have not been impacted since the sanction of Muskrat Falls, and that Hydro's long term asset management plan for that facility is consistent with the plant's end of life plans while at the same time ensuring a safe, reliable, and environmentally sustainable operation.

In the context of Hydro's existing work, which began in 2011, related to critical spares, AMEC recommended that Hydro continue to follow through on its existing process improvement initiative related to asset criticality and critical spares, with a focus on Hydro's critical spares strategy for generation assets. This will involve building on current existing practises and integrating the various critical spares plans across Hydro to achieve a more comprehensive and cost-effective approach, following the incidents of January 2014.

Other Findings

AMEC recommended that a more rigorous winter readiness program be introduced, building on the winter readiness self-assessment already in place. Hydro agrees with this recommendation.

5.1.4 *Generation Availability*

Overall Assessment

The availability and performance of Hydro's hydroelectric and oil-fired thermal generating assets up to 2013 has been consistent with, or better than, Canadian industry averages. Hydro's hydroelectric assets have performed to a high level and much better than the CEA average on a De-rated Adjusted Forced Outage Rate (DAFOR) basis. Hydro's oil-fired thermal assets have historically tracked closely with the CEA average on DAFOR. Last year (2013) was a notable exception because of the failure of Unit 1 at Holyrood and the extended repair period that followed.

Depending on reservoir status related to precipitation and weather trends generally, the extent to which Holyrood is relied on in any given year to serve load outside the winter months (December to March) is limited. Holyrood units are purposely out of service for maintenance during the extended non-winter season, when they are not required.

Hydro's generation asset base is aging. Based on the in-service dates of Hydro's various generation facilities and any significant upgrades to those facilities, 62% of these assets are older than 35 years; 55% are older than 40 years. This is typical in Canada, and many utilities are in the same position as Hydro and have been re-investing heavily in infrastructure renewal. Hydro's asset management and renewal program is comprehensive, deliberate and rigorous, and this has served to maintain and, in some cases, improve generation reliability.

As noted below, the performance of Hydro's gas turbines has not been to an acceptable standard. All gas turbine units have been the subject of detailed condition assessments, which have been the basis for an extensive multi-year maintenance and overhaul investment over the past several years and which is ongoing.

Relevant Background

From an operations perspective, Hydro manages its generation resource availability on the Island Interconnected System, and schedules generation unit outages for planned maintenance in such a way as to maintain a (n-1) system contingency reserve criterion. In other words, generation assets are managed so that total load can be met in the event of an unplanned loss of Hydro's largest available generating unit.

Going into December 2013, Hydro's generation availability met this reserve criterion, and with the planned completion of the Hardwoods Gas Turbine overhaul on December 21, 2013 Hydro would have continued to meet the reserve criterion going into the severe weather period in early January 2014.

This plan was disrupted by a series of unplanned generation outages as follows:

a) A de-rating of the Exploits plant on December 15, 2013 because of frazil ice (25 MW);
b) A de-rating of the Granite Canal plant on December 16, 2013 (8 MW) due to a vibration issue;
c) The failure of the Hardwoods Gas Turbine on December 21, 2013 due to a fuel control valve failure (50 MW);
d) A de-rating of Unit 2 in Holyrood on December 25, 2013 because of a broken control valve (25 MW) (recovered by January 3, 2014); and
e) A de-rating of Unit 3 in Holyrood on December 26, 2013 due to a failed forced draft (FD) fan motor (100 MW).

During this period, generation availability issues were being addressed on a priority basis by Hydro as noted in the focus area reports.

Combined with an existing de-rating of 25 MW at the Stephenville Gas Turbine, the total generation that was unavailable in late December 2013 was 233 MW. As a result of these generation outages and in preparation for forecast load, on December 29, 2013 Hydro initiated discussions with Corner Brook Pulp and Paper (CBPP) to finalize an interruptible power arrangement under which Hydro would be able to access available generation from CBPP. This arrangement was reached quickly and CBPP reduced mill operations to make up to 60 MW of power available to Hydro as required from December 31, 2013 forward.

The generation availability issues during December 2013 involved five different generation plants and two different units at Holyrood. This would be highly unexpected given Hydro's focus on asset management, reliability and winter readiness. These generation issues were unresolved on January 2, 2014, and unavailable generation was the main factor in Hydro's inability to meet full load on that day and the rotating outages that followed. All but the de-rating on Unit 2 in Holyrood (which was repaired while on line on January 3, 2014 at 12:00) continued until January 12, 2014. This generation unavailability, with the addition of Unit 1 in Holyrood due to the breaker problem, combined with higher than normal transmission line losses due to the required use of off Avalon generation, and the sustained severe cold weather experienced in early January 2014, continued to contribute to the rotating outages through to January 8, 2014.

Residual cooling issues on one end of the turbine in Stephenville, and the failure of a fuel control valve coincident with final commissioning at Hardwoods in late December 2013, resulted in the unavailability of Hardwoods through the outage period in January 2014, and a de-rating of the Stephenville gas turbine from 50 MW to 30 MW (subsequently 25 MW).

The transmission disruption in Sunnyside on January 4, 2014 resulted in temporary generation trips around the hydroelectric system which were quickly rectified. The three units in Holyrood were affected as well, although they took longer to restore. Units 2 and 3 were restored by 21:34 on January 4, 2014 and 01:33 on January 5, 2014 respectively. The run-up and restoration of Unit 1 took longer because of vibration issues, but it was available by 21:30 on January 5, 2014. However, as discussed in more detail in a later section, the unit tripped again because of the failure of breaker B1L17 in the Holyrood switchyard. Unit 1 was eventually restored on January 8 after this breaker issue was resolved.

Key Findings

The performance of Hydro's Gas Turbines has historically been below CEA benchmarks. Detailed condition assessments performed in 2007 and 2008 at both Stephenville and Hardwoods were the impetus for a multi-year asset renewal program for these facilities, including major overhauls at both locations. Major upgrades were competed at Hardwoods in 2013 and at Stephenville in 2012 and 2013, with further work planned at that facility in 2014 and 2015.

Hydro is confident that the reliability of these generation assets will be improved and closer to industry standards going forward as a result of the significant upgrade and maintenance work performed on these units over the last 12 to 18 months, and the further planned work. However, Hydro believes that further focused attention is required, and a series of recommendations made in the Generation Availability Report (Schedule 6) that are specific to gas turbine availability will be incorporated into Hydro's immediate term action plan.

Other Findings

The issue of critical spares has been addressed in the above discussion of asset management practices. Other findings related to generation availability have been documented in the detailed focus area report.

5.1.5 *Transmission Availability*

Overall Assessment

The design of Hydro's transmission network follows industry practices and provides a reliable and robust network. The independent review by AMEC highlighted that the performance of Hydro's bulk transmission system compares very favorably with CEA averages. Between 2004 and 2012, Hydro has considerably out-performed comparable Canadian utilities for both 230 KV transformers and breakers. Transmission line performance has been a little more variable, with results that are both above and below CEA benchmarks.

Henville Consulting noted that Hydro's protection and control systems are applied according to typical North American standards. During the system disturbances that occurred on January 4 and 5, 2014, the transmissions lines and system transformers were operating in many unusual conditions and with unusual system stress. Despite these conditions, most of the protection operations that were initiated by these events were correct, desirable and easily explained. Some of these transformer and breaker protection operations did not operate as expected during these events. These are discussed below and addressed in the findings.

Hydro has documented processes and facilities in place to deal with system disruptions on a timely basis when they do occur, and these were effectively deployed in response to the system disruptions on January 4 and 5, 2014. They include the following:

a) A documented restoration plan for loss of supply to the Avalon Peninsula;
b) Critical spares inventories located in key locations to ensure optimum availability;
c) A decentralized location of staff and crews around the island (and in Labrador) to ensure proximity to key transmission infrastructure;
d) An arrangement with Newfoundland Power which provides for the sharing of equipment, people and other resources if needed in an emergency situation; and
e) A Backup Control Centre (BCC) at an alternate location which is available as an alternative ECC in the event that the Hydro Place ECC is rendered unavailable.

Relevant Background

Both of the external consultants engaged by Hydro to assist in Hydro's review of transmission availability commented on the highly unusual sequence of separate equipment failures that occurred on January 4 and 5, 2014. All of these events were related to transformer and breaker failures and involved protection system operations. Henville Consulting observed in their report that industry best practices do not dictate that protection system designs must handle multiple independent contingencies on power systems, such as those experienced by Hydro in early January 2014, on the basis that such contingencies are normally viewed to be non-credible (i.e., extremely unlikely).

Hydro's performance on the bulk transmission system has historically compared very favourably with the national average as reported by the CEA benchmarks. Between 2004 and 2012, the latest year for published results, and based on a five year rolling average Hydro considerably outperformed comparable utilities represented in the CEA average, for both 230 kV transformers and circuit breakers. For 230 kV transmission lines Hydro posted results that were more variable with some results above and others below the CEA averages.

Four transmission system events, which activated protection and control systems, caused the system disruptions that occurred on January 4 and 5, 2014, or contributed to delays in effecting a restoration of power. The four events were:

a) T1 transformer fault and Sunnyside Breaker Failure at 0905 on January 4, 2104 that initiated a system wide interruption resulting in the isolation of the Avalon and Burin Peninsulas from the remainder of the power grid and the shutdown of the Holyrood Generating Station.
b) T5 transformer tap changer failure at the Western Avalon terminal station at 1222 on January 4, 2014 which caused a delay in the restoration of service to customers supplied from that station.

c) Sunnyside Restoration Failure at 1533 on January 4, 2014 which initiated a second system wide interruption. This resulted in the tripping of two lines and the isolation of the Avalon and Burin Peninsulas as well as the Come By Chance refinery.

d) Breaker Failure, Holyrood – B1L17 at 2127 on January 5, 2014 which initiated a shutdown of the Holyrood Generating Station and the interruption of supply to customers primarily on the Avalon Peninsula.

These events were analyzed in detail using the TapRooT® root cause analysis process[6]. The Root Cause Report is provided in Schedule 8 to this Report, and contains detailed descriptions of each of these events, as well as recommendations flowing from the Root Cause Analysis Team's (RCAT) analysis. The key results are summarized below.

1. <u>T1 transformer fault and Sunnyside Breaker Failure</u>

Identified casual factors:

a) Fault on T1 transformer.
   Root cause: There was no online mechanism to detect combustible gasses in the transformer which may have provided an early detection of the problem.
b) One of the five breakers protecting T1 did not trip (B1L03).
   Root cause: Findings are currently inconclusive and further investigation is required to determine whether high impedance paths exist in the control system which may affect the breaker.
c) T1 protection did not initiate breaker fail protection.
   Root cause: During the design of the station, the simultaneous failure of a transformer and a 230kV breaker was considered to be too low of a risk to protect against.

[6] TapRooT® is a highly structured investigative process designed to focus on the identification of causal factors and specific problems of clearly specified events. By its nature, the purpose of the TapRooT® analysis is to determine the root cause and identify corrective actions directly related to the problem being investigated. In the course of an investigation, TapRoot® often identifies additional areas for consideration that are not directly related to the cause of the problem. TapRoot® is recognized as an industry best practice for investigative processes.

2. <u>T5 transformer tap changer failure, Western Avalon terminal station</u>

Identified causal factors:

a) Fault on T5 diverter switch.

Root cause: Findings are currently inconclusive. The RCAT recommended further investigation of this event, and that the possibility of a transient overvoltage due to system harmonics should be included as a consideration.

3. <u>Sunnyside Restoration Failure</u>

Identified causal factors:

a) Breaker B3T4 closed with a trip condition present.

Root cause: The design of the station protection scheme is such that isolation of the T1 transformer would not block the initiation of B3T4 breaker failure.

b) Breaker B1L02 did not trip because Bus 1 protection is blocked.

Root cause 1: The Protection and Control Supervisor onsite at the time of the fire was relatively unfamiliar with the protection wiring configuration.

Root cause 2: The protection scheme was not designed utilizing standard conventional applications of the re-trip function with respect to breaker failure applications.

4. <u>Breaker Failure, Holyrood – B1L17</u>

Identified causal factors:

a) Breaker Phase "A" failed to open

Root cause: Work Method did not contain instructions on how to prevent moisture contamination of the breaker air receiver tanks while interrupters were removed for repair.

b) Work Package needs improvement

Root cause: Work package for applying Room Temperature Vulcanizing Coating (RTV) for interrupters requires they be removed from the main receiver tanks for the duration of the RTV application.

c) Scheduling needs improvement

Root cause: As a result of maintenance personnel being rescheduled to perform high priority work, the reinstallation of breaker B1L17 interrupters was extended in early 2013.

Key Findings

AMEC indicated in its report that the design of the transmission network follows industry practice and provides a reliable and robust network. The events that occurred during the January 4 and 5, 2014 outages involved multiple events which are not typically planned for.

AMEC also noted that Hydro's internal technical staff and external consultants involved in the event review, as well as Hydro operations staff, are knowledgeable, experienced and professional, and Hydro should consider how it can best transfer the knowledge and experience gained during the event and in the investigations to the rest of the organization.

The prevalence of 230 kV breaker failures during the events of January 4 and 5, 2014 as well as the age and maintenance-intensive nature of this terminal station equipment, are indicative of a need to take action to mitigate against future failures of these key components. AMEC recommended that Hydro should accelerate its existing breaker replacement program, and Hydro agrees with this.

Certain aspects of transformer, breaker and breaker fail protection design were identified by both the RCAT and Henville Consulting as either contributing to the transmission disruptions and outages on January 4 and 5, 2014 or as protection design schemes which should be reviewed for their continued applicability in light of these events. All of these recommendations will be reviewed by Hydro and incorporated into 2014 or 2015 workplans, as appropriate.

Other Findings

There are additional recommendations presented in the focus area report. However, no other material transmission availability factors were identified as having initiated or contributed to the system disruptions on January 4 and 5, 2014.

5.1.6 *Emergency Response and Restoration*

Overall Assessment

Hydro has established processes for emergency response and system restoration at both the corporate and field operations levels. These were deployed in a way that enabled Company personnel to response to the Sunnyside emergency situation, and the system disruptions that followed, in an orderly and purposeful manner. Company personnel responded in poor weather with a sustained effort, in what was a stressful situation, in hazardous conditions – and they did so safely.

On January 4, 2014 the on-scene emergency response that was coordinated by the on-scene commander at Sunnyside was supported by TRO Operations resources in Bishop's Falls, and by a partial mobilization of the Corporate Emergency Operations Centre (CEOC) in St. John's, including all necessary personnel. The local emergency response and fire response were well coordinated in consultation with the local communities, and safely executed. The team that deployed to the CEOC was available to provide corporate emergency support as needed and included personnel from System Operations, Project Execution and Technical Services, Supply Chain Management, Safety and Health, Environmental Services; and Corporate Relations.

The system disruptions at Sunnyside caused multiple generation trips around Hydro's system. However, for the most part, these were brief and the units were restored within a short period of time. Delayed restoration and a subsequent trip at Holyrood were related to a breaker failure in the Holyrood switchyard. Once this was diagnosed and corrected, Holyrood restoration was carried out as expeditiously as possible.

Relevant Background

As the severe weather in Newfoundland intensified on January 3, 2014 and in light of the short term forecast for the coming days, various emergency preparedness measures were taken by Hydro to ensure its ability to respond to any system emergencies that might occur. A coordination call was held early on January 3, 2014 involving executive management and senior personnel from System Operations, Project Execution and Technical Services, TRO, Hydro Generation (Bay d'Espoir), Holyrood Thermal Generating Station (HTGS); and Corporate Communications. The contingency actions that were taken following this meeting included the following:

a) Crews were deployed to selected terminal stations early the following morning;
b) Crews were dispatched to the Cat Arm and Granite Canal generating stations (normally unstaffed);
c) Extra maintenance staff were scheduled in Holyrood for the morning of January 4 and staff were put on standby;
d) Operating procedures for startup and shut-down of generating units in the event of a system trip were reviewed;
e) A blackstart plan for HTGS was discussed with the ECC; and
f) Extra snow-clearing was arranged at Holyrood to ensure the main roads to these plants and switch yards were clear and accessible.

The initial disruption of power supply began at 0905 on January 4, 2014 resulting in the loss of power to the Avalon Peninsula and wider system impacts.

Because storm preparation plans had been deployed the previous day as a contingency, Hydro personnel were on-site at Sunnyside Terminal Station at the time of the initial incident. As a result, they were able to immediately communicate this event and initiate the necessary processes for emergency response and restoration. With the knowledge of the situation in Sunnyside, the ECC, operators proceeded with restoration of the transmission network to restore service to customers. The ECC operator began restoration by starting at Come by Chance at 09:27.

Difficulties with a breaker in the Western Avalon Terminal Station resulted in some delays. The operator adjusted the restoration sequence due to this problem. As a result, the first Avalon Peninsula station restored was Hardwoods at 0951. After that, significant customer restoration began. The station service to Holyrood was restored at 1024 enabling a restart of the generating units at the plant and restoration of customers supplied from the Holyrood Terminal Station.

Restoration of Oxen Pond Terminal Station followed at 10:41. At this point, the stations on the Avalon Peninsula, with the most customers connected, were ready to start coordinated customer restoration with Newfoundland Power.

The Energy Management System (EMS) in the ECC shut down at 11:03 and restoration was delayed until 11:46 when the EMS was restored to operation.

At 12:22 the Western Avalon Terminal Station was restored. However, a failure within transformer T5 occurred at this time delaying full restoration of the station until 14:37, at which time all stations were restored with the exception of the Sunnyside Terminal Station.

Restoration of Sunnyside Terminal Station was impeded during the early hours of January 4, 2014 by the intensity of the fire and smoke on T1 and Hydro's immediate concern with ensuring that both employees and the surrounding community were safe, as well as making plans for fighting the fire and bringing it under control. The on-site crew was also occupied with surveying any damage to surrounding equipment in making preparations for a safe isolation of T1 in a way that minimized environmental impacts, and then restoring power.

The two attempts to restore power from Sunnyside at 12:58 and 15:33 respectively on January 4, 2014 were unsuccessful for the reasons noted in Hydro's root cause analyses. Emergency modifications that were made on-site to the Sunnyside protection scheme in order to go around the damaged protection circuitry on T1 produced unexpected line trips when the ECC attempted restoration on both occasions. This was compounded by two aspects of protection scheme design within the station that also produced unanticipated events when ECC restoration was attempted.

The cause of the second interruption was quickly resolved and the ECC successfully restored all affected transmission lines by 16:19.

The initial system disruption at Sunnyside caused by the T1 fault resulted in several of Hydro's generation units tripping off-line. These included Paradise River; Stephenville Gas Turbine; Holyrood; Star Lake; Cat Arm; Hinds Lake; and Upper Salmon. With the exception of the Holyrood units, all of these disruptions were temporary, and the units were restored within an hour or so, except for Cat Arm which was fully restored by 13:00.

Further generation trips occurred after the second restoration attempt at Sunnyside at 15:33 involving the Cat Arm plant. The Cat Arm plant was restored within an hour.

The initial restoration of generation at Holyrood after the transmission disruptions at Sunnyside on January 4, 2014 occurred in a prudent and timely manner. Units 2 and 3 were restored at 21:34 on January 4, 2014 and 01:33 on January 5, 2014 respectively. The run-up and restoration of Unit 1 took longer because of vibration issues, but it was available by 21:30 on January 5, 2014. Additional disruptions in generation at Holyrood occurred after this point. However, these were related to breaker and switchyard issues, and were not related to the availability of the generating unit.

During the restoration of Unit 1 on the evening of January 5, an unknown failure on breaker B1L17 in the Holyrood switchyard caused the unit to trip, which in turn caused protection systems to activate and take Units 2 and 3 off-line. Restoration efforts were dedicated to Units 2 and 3 which were back on line at 05:29 and 07:17 the next morning. As noted earlier, Unit 1 was eventually restored on January 8, 2014. Unit 3 was restored to its full capacity on January 12, 2014 after the re-installation of the FD fan motor.

The restoration of generation sources in response to the larger system disruption on January 4, 2014 was executed in a timely fashion, and in a manner that ensured the safety of employees and the operational integrity of these assets. Contingency plans which ensured that crews were on site or would have unimpeded access to facilities were a factor in Hydro's success in re-instating generation affected by the Sunnyside events.

Key Findings

The dedication and commitment of Hydro workers to safety, was demonstrated through the safe execution of the emergency response and restoration activities. There were no safety incidents during the restoration efforts and crews maintained their focus on safety when faced with the challenging circumstances of a transformer fire in a live switchyard, poor weather conditions, cold temperatures and knowledge of widespread customer outages.

As well, the commitment and involvement of external agencies such as local fire departments, Fire and Emergency Services and other Government of Newfoundland and Labrador departments, that were called upon to provide support during the events, greatly assisted in the restoration efforts.

Other Findings

In addition to the recommendations laid out in the focus area report provided as a schedule to this Report, and in the interests of continuous improvement, Hydro will continue to review and improve its emergency response programs. This will include engagement with external stakeholders.

5.1.7 *Coordination and Communication with Customers*

Overall Assessment

With the magnitude of the supply disruptions in January 2014, the focus of Hydro was on the restoration of power to customers. During the events, Hydro was also focused on ensuring that it was providing timely and accurate information to customers, including specific information on the conservation request, and coordinating with Newfoundland Power and CBPP. Generally, all reviewed areas performed well, however, there were some areas for improvement identified. In particular, a clear protocol for customer notification of system supply issues should be formalized.

Relevant Background

Real-time, two way communications between the System Operations groups in Hydro and Newfoundland Power was regular and ongoing leading up to, and throughout, the period of rotating outages. On January 2 and 3, 2014 the companies were in contact with each other to discuss the scheduling of each and every feeder outage, which both companies eventually agreed was not optimal in terms of minimizing the duration of customer outages as much as possible and in terms of ensuring the most timely communication possible with customers and the general public. The outage coordination process was streamlined on January 3, 2014 and operated more effectively for the duration of the outages.

Hydro and Newfoundland Power have established protocols for the coordination of power system operations and feeder rotations in the event of a system disruption, and these worked effectively both leading up to, and during, the events of January 2-8, 2014.

The coordination of a capacity assistance agreement with CBPP, under which CBPP made up to 60 MW available to Hydro as needed, was done expeditiously, when it became apparent in late

December 2013 that meeting full load might be an issue. This was important to the ability of Hydro and Newfoundland Power to minimize the frequency and duration of outages as much as possible.

Hydro and Newfoundland Power communicated with each other with respect to system and customer-related matters on a frequent basis, to ensure that customers and the general public were kept informed on key developments. Hydro used traditional, social and digital media to provide information and Hydro spokespersons were readily available to media during and after the supply disruptions. Hydro's customer call centre was also open when required during the outages to respond to customer enquiries. A public survey conducted post-event indicated that while respondents said that Hydro could have provided more information/updates during the outages, respondents also indicated that Hydro's communication with the public was one of the top things that Hydro did well during the events. The report by NATIONAL Public Relations also shows that Hydro had a significant presence on social media, which is an effective means of sharing information, and that Hydro was successful in reaching its target audience: customers and members of the general public. The report by Cathy Dornan Public Affairs indicates that Hydro did a very good job of communicating to the public and ensured that the public had reliable information.

The call for customer conservation on January 2, 2014, despite the relatively short notice, was effective in Hydro's opinion. Although it was difficult to quantitatively measure the actual impact in the circumstances, Hydro believes that customers responded positively to this call for conservation and the coordinated public campaign with the Government of Newfoundland and Labrador and Newfoundland Power, which sustained that request over the following days. Many anecdotal stories support the view that customers actively reduced their electricity consumption over this period, and this was verified by the results of a post-outage survey conducted for Hydro by MQO Research where 86% of respondents indicated they took energy conservation steps during the outages they otherwise would not have taken.

Key Findings

Considering the January 2014 supply disruption activities, Hydro's System Operations requires a formal protocol for advising internal and external stakeholders to determine if a conservation request is necessary. Corporate Communications also requires a clear protocol for advising the public of the conservation request in a timely manner.

Other Findings

To ensure consistent information and continual improvement, Hydro recommended that daily summary meetings between the utilities would further assist with joint public communication efforts.

Hydro's internal review has identified other opportunities for improving its processes in relation to customer coordination and communication in the event of supply disruptions and rotating outages. These are detailed in Schedule 10 to this Report.

5.1.8 *Technology and Communications Infrastructure*

Overall Assessment

Overall, Hydro's network and communications infrastructure performed well and as expected throughout the full duration of the supply disruptions and rotating outages in January 2014. Hydro's network services and tele-protection systems, and their associated backup power systems which are located at various terminal stations, microwave sites, and other remote/unstaffed locations, are critical to maintaining the integrity of the island interconnected system. All of these systems operated as designed.

However, for a period of 43 minutes the EMS[7] computer was unavailable for ECC operators due to a brief loss of power and the time required to restart and bring the EMS back into operation.

[7] The EMS is a sophisticated software application used by Operators in Hydro's ECC to manage and control Hydro's power system.

Relevant Background

Hydro Place experienced a power outage on the morning of January 4, however except for a very brief period before power was restored to Hydro Place, Uninterruptible Power Supply (UPS) backup batteries were effective in maintaining power to these systems. When the short interruption in power between UPS availability and building power restoration caused the EMS and computing systems to shut down at 11:03, on-call systems support were immediately contacted and reported to Hydro Place within a half hour. Within 15 minutes of their arrival the EMS completed its recovery process and was once again available to Operators at 11:46.

Both the EMS and administrative computing systems are protected against a loss of feeder power by UPS batteries and backup diesel generators located at Hydro Place. The UPS batteries performed as expected, however despite regular testing and recent maintenance, the backup diesel generation did not perform as expected. These diesel generators are run-tested every two weeks, and are subject to an annual preventative maintenance inspection by an external contractor. The latest annual inspection was completed on December 27, 2013

While the EMS was unavailable, ECC Operators reverted to Hydro's Instruction 015 which is Hydro's contingency protocol for manual operation of the power system during a loss of the EMS and focused on maintaining system stability rather than restoration.

Hydro's administrative computing systems were unavailable for an approximate four hour period on January 4, 2014 between 11:03 and approximately 15:00. These systems host a very wide array of applications, databases and services, and a gradual and planful restoration of the servers was required. While this was an inconvenience for the operations and head office personnel who were responding to the Sunnyside system disruption (e.g., unavailability of on line work permitting, unavailability of the Hydro web site), Hydro's internal review did not identify any material impacts on system restoration efforts.

Key Findings

Overall, Hydro's technology and communications infrastructure performed well and as expected during the supply disruptions and outages in January 2014. With respect to the loss of the EMS, Hydro has taken steps to address the issues related to back up diesel generation for the EMS system.

Other Findings

During the power outage to Hydro Place on January 4, 2014 contact with Newfoundland Power was required to ensure that the Hydro Place feeder was restored on a priority basis. This identified the necessity of establishing a formal protocol with Newfoundland Power to ensure that the Hydro Place power feeder is kept in service as a priority in the event of a power interruption, and restored as soon as possible if the feeder is interrupted.

5.2 Actions Taken and Planned

Hydro's internal review has been comprehensive. Hydro has assessed the various recommendations made by both internal teams and independent consultants as generally falling into one of three categories:

1. **Key actions** that are required to address factors or conditions which caused or directly contributed to the supply disruptions and outages in January 2-14.
2. **Other priority** actions that are required because they have a high potential to significantly reduce the risk of similar system events occurring in the future; and
3. **Other opportunities for improvement** that are not high priority and are addressed in the focus area reports, but which should be evaluated for their potential benefit and implemented as time and other priorities permit.

This Section focuses on key findings and actions in the first instance, and secondarily on other high priority actions. With respect to other recommendations made by internal teams and external consultants, the appropriate accountable executives have been directed to ensure that these are itemized, evaluated and incorporated as needed into a proposed multi-year action plan by the end of April, 2014.

An integrated action plan will be reviewed and approved by the Hydro Leadership Team and by Hydro's Board of Directors by the end of April, 2014. The appropriate Vice Presidents will be accountable for periodically reporting the progress and status of the actions for which they are responsible to the President and CEO. The Vice President of Hydro will be responsible for the overall coordination, integration and tracking of these action plans.

5.2.1 Key Actions

Area	#	Description	TCD/Status
GP	1	Generation Planning: Expand the level of sensitivity testing for alternate weather and generation availability scenarios into the generation expansion planning process.	 April 2014
GA	2	Gas Turbines: a) Implement recommendations identified through the internal review relating to gas turbine availability, including: - review of gas turbine maintenance practices - assess the effects of test starts and run-ups prior to severe weather - identify repeat failure events and address the root causes - identify plan required for additional plant and equipment refurbishment not already completed - review fuel storage processes and procedures b) Create a senior position reporting to the Vice President for Hydro whose accountability includes the oversight of asset management plans, maintenance standards, and capital submissions related to gas turbines.	 In progress May 30/14 May 30/14 Aug 30/14 April 30/14 April 30/14 Complete

TA	3	230 kV Breakers: a) Review the current 230 kV breaker replacement plan and revise for accelerated replacement, with a priority on identifying the activities and areas to be completed during the 2014 maintenance season. b) Review the existing preventative maintenance program for 230 kV breakers and identify any changes required, including the Preventative Maintenance (PM) cycle, and consider breaker seal risks associated with cold weather effects. c) Revise the Work Methods pertaining to the repair of 230 kV breakers.	April 30/14 April 30/14 May 30/14
AM	4	Complete the planned initiatives in Hydro's Integrated Critical Spares Strategy as well as implement improvements identified by the Critical Spares Council in 2013. In the process revisit Hydro's critical spares philosophy for Holyrood and other generation assets within Hydro's system, and implement any changes in time for the 2014/15 winter season.	Ongoing Nov 15/14
TCD = Target Completion Date			

5.2.2 Other Priority Actions

A completion date review is underway in relation to the following action items, dates to be finalized in Q2 2014.

Area	#	Description
LF	1	Review the updated version of the short term seven day operating forecast to determine if it provides an improved correlation in extreme cold weather situations. If not, investigate alternative models and implement available enhancements prior to the 2014/15 winter season.

AM	2	Review current winter readiness program in reference to industry best practices and formally implement/document for Hydro operations.
AM	3	Continue evaluation and implementation of work planning, scheduling and execution improvements.
P&C	4	Finalize evaluation of high priority recommendations by Henville Consulting and the Root Cause Analysis Team.
CC	5	Implement a formal protocol for notifying customers, end users and the general public in relation to pending supply issues and conservation requests.
TCI	6	Identify and address the factors which caused under-frequency/synchronization and over-heating issues on the back-up diesels at Hydro Place in early January.

6 WINTER SEASON SUPPLY PLAN

Since the events of January 2 to 8, 2014, Hydro has been meeting the forecast load for the remainder of the 2014 winter period. As well, Hydro is taking steps to ensure that sufficient generation is available to meet the forecast winter peaks until Muskrat Falls and the Labrador Island Link come on line to provide significant additional generation to the province's power system.

6.1 Winter 2014

Since the supply disruptions and outages in January 2014, Hydro has investigated and substantially resolved the various generation issues that occurred in December 2013 and January 2014. The following specific actions have been taken:

1. Holyrood Unit 3: Unit 3 was restored to full service at 150 MW on January 12, 2014 following the installation of a re-wound FD motor fan.
2. Holyrood Unit 1: Unit 1 was restored to 165 MW with a minor de-rating of 5 MW on January 8, 2014. Minor turbine vibration issues will be addressed more fully in 2014,

however, the Holyrood operations group have developed a re-start protocol for this unit which ensures it can bought back to full load from a full stop within four hours.

3. Hardwoods Gas Turbine: Following repairs to address a fuel control valve issue, the Hardwoods gas turbine was returned to full service on January 12, 2014.
4. Stephenville Gas Turbine: The current status of the unit is an availability of 25 MW on End A, and 20 MW on End B. There is also full synchronous condenser capability. End B experienced a failure of its engine on January 8, 2014. A replacement engine with a capability of 20 MW was placed in service on February 26, 2014. Work is ongoing with the equipment provider to assess the damage and complete a repair to the original engine.
5. Exploits-Grand Falls: Exploits generation returned to normal production after the frazil ice issue was fully resolved on January 15, 2014.

As of March 22, 2014 all Hydro generation assets are available, with the exception of Unit 6 (75 MW), and minor de-ratings at Holyrood (28 MW) and Stephenville End B (10 MW), resulting in a total generation capacity of 1,615 MW.

Hydro is also in the process of installing blackstart capability at the Holyrood Thermal Generating Station. With some modifications to enable an extended operation at 14 MW if necessary, this facility can be used to provide peak power when required, and is expected to be in service in March, 2014.

Hydro has also extended its capacity assistance agreement with CBPP. The term of the original arrangement reached in December 2013 was to the end of January 2014, and this was extended through the remainder of the winter period to March 31, 2014. Under this arrangement, Hydro can access up to 60 MW of power, in 20 MW blocks, when needed.

In the short term, actions will continue to be taken in the normal course of operations to ensure the reliability of existing generation. Standby diesels and gas turbines are tested monthly to ensure availability. As well, since the events of January 2-8, 2014, Hydro has implemented a protocol for running up the gas turbines in Stephenville and Hardwoods in advance of all significant forecasted weather events.

6.2 Winters 2015-2017

The most recent generation planning analysis in 2012 projected a capacity deficit occurring in 2015 and it recommended the addition of a 50 MW combustion turbine by December 2015 as the least cost solution to mitigate the anticipated deficit. The 2012 recommendation recognized that during early 2015, prior to the installation of the combustion turbine, the LOLH of the system would in fact be greater than the 2.8 hour threshold.

Hydro is reviewing its capacity planning options to ensure a combustion turbine is still the best option given the system disruptions in January 2014, and to identify means to fully mitigate the forecasted 2015 deficit. Other options under consideration include the following (a combination of two or more options may be developed to meet the potential deficit):

1. Retain the diesel facility being installed at Holyrood for blackstart capability (presently under a lease-to-own arrangement for commissioning in March 2014). Once installed, 10 MW can immediately be supplied to the system on a sustained basis. With some modifications, the facility can be made to deliver the full 14.6 MW peaking capacity to the provincial grid.
2. Enter into interruptible contracts with large Industrial Customers. Discussions with Industrial Customers (CBPP, Vale and North Atlantic Refining) were initiated in fall 2013. These discussions are ongoing and options continue to be explored.
3. Seek already built combustion turbines in the 50 to 100 MW range to supply deficit and blackstart at Holyrood. Preliminary discussions indicate that these options may be able to meet the 2015 requirement. However, discussions with manufacturers, brokers and owners are ongoing to determine the delivery times, operating experiences, and the extent of modifications and facilities required to connect to the Island Interconnected System.

4. Initiate the supply of a new combustion turbine for the Holyrood site to supply deficit and blackstart functionality. All preliminary engineering is complete. With final approval by June 2014, this plant could be in-service by late 2015.
5. Continue and enhance conservation and demand management initiatives, with the focus on demand management. Work is being conducted to assess customer end use options with a view of providing demand management. This is considered a supplemental means of meeting the deficit and may provide further cost savings opportunities when combined with other options.

The project or combination of projects that will be implemented for the winter of 2015 are currently forecasted to be the last new island generation that will be required prior to the commissioning of Muskrat Falls and the Labrador Island Link in late 2017 or early 2018. Muskrat Falls and the interconnection with the North American grid will greatly enhance Hydro's capacity and reserve. It will be many years before Hydro has to again consider adding capacity to the Island Interconnected System.

Ventyx confirmed that Hydro's generation planning process conforms with industry standards. That being said, they did identify an opportunity to improve Hydro's generation planning on a go-forward basis by integrating an expanded sensitivity testing in its generation planning model. Hydro has previously identified the need for adding new generation capacity in 2015, and sensitivity testing recommended by Ventyx will be incorporated into Hydro's currently ongoing analysis of the options and preferred strategy to validate the size and timing of the optimum capacity addition from a cost/reliability perspective. This will be the subject of a submission to the PUB in early April, 2014.

NEWFOUNDLAND AND LABRADOR HYDRO

Glossary of Terms

AC – See Alternating Current

Alternating Current (AC) – A continuous electric current that regularly reverses direction, usually sinusoidally. Alternating current is used in power systems because it can be transmitted and distributed at various voltages by transformers more economically than direct current.

Alternator – an electromechanical device that converts mechanical energy to electrical energy in the form of alternating current.

Asset Management – the comprehensive management of asset requirements, planning, procurement, operations, maintenance, and evaluation in terms of life extension or rehabilitation, replacement or retirement to achieve maximum value for the stakeholders based on the required standard of service to current and future generations.

BCC – Backup Control Centre

BCC DRP – Backup Control Centre Disaster Recovery Plan

BDE - Bay d'Espoir Hydroelectric Generating Facility

Black Start – The process of restoring a power station to operation without relying on the power transmission system.

BOD – Board of Directors

Bus – A series of conductors, usually three, supported by metal structures inside a terminal station that connects various parts of a switchyard such as Transmission Lines, Breakers and Transformers.

Bus Lockout – A protection device used to electrically isolate a section of a utility switchyard when an electrical fault is sensed. The Bus Lockout is used to open the Breakers and Disconnects to stop more electricity from entering the problem area when a fault is detected.

Capacity - The highest level of electricity that can be supplied at any one time. For residential customers, capacity is measured in kilowatts (kW), on the electricity system it is measured in megawatts (MW).

CBC – Come-by-Chance

CBC TS – Come By Chance Terminal Station

CBPP – Corner Brook Pulp and Paper

CCCT – Combined Cycle Combustion Turbine

CCG – Canadian Coast Guard

CDM – See Conservation Demand Management

CEA – Canadian Electricity Association

CEO – Chief Executive Officer

CEOC – Corporate Emergency Operations Centre

CERP – Corporate Emergency Response Plan

Circuit Breaker – An automatic electrical switch designed to open/break a circuit in order to protect electrical equipment, such as transformers, from damage caused by overload or short circuit.

CM – See Corrective Maintenance

Cold Load Pickup – Phenomenon that usually occurs in cold weather which takes place following an extended outage in which the overall demand on a distribution feeder, following its restoration, is greater than what would be expected in normal circumstances. In many cases, for a period of time once the circuit is restored, the level of demand is greater than the level experienced before the outage.

Conductor – A type of material which permits the flow of electric charge in one or more directions. Usually made of aluminum or copper.

Conservation Demand Management (CDM) – Refers to programs and activities that are designed to reduce electricity consumption or peak electricity demand behind customers' meters. These can include providing incentives and rebates, load control programs and others. Hydro’s programs have focused on the conservation of electricity consumption.

Corrective Maintenance (CM) – a maintenance task performed to identify, isolate and rectify a fault so that the failed equipment, machine, or system can be restored to operational condition.

CPW – See Cumulative Present Worth

Critical Spare - A part which could cause significant downtime in production if failure occurs. Generally these are parts that have a high cost and relatively low probability of failure. Replacements of these assets are not available on demand from a nearby source and require long delivery times.

CT – Combustion Turbine

Cumulative Present Worth (CPW) – The present value of all incremental utility capital and operating cost incurred by Hydro to reliably meet a specific load forecast given a prescribed set of reliability criteria.

Current – a flow of electric charge through a medium

DAFOR – See De-rated Adjusted Forced Outage Rate

Demand Losses – The electrical losses on the transmission lines and transformers, measured as the differences between generation source and delivery point.

De-rated Adjusted Forced Outage Rate (DAFOR) - a reliability key performance indicator for generation assets. DAFOR measures the percentage of time that a unit or group of units is unable to generate at its Maximum Continuous Rating (MCR) due to forced outages.

Distribution – The final stage in the delivery of electricity to customers. The distribution system carries electricity from the terminal station, where the transmission system terminates and delivers it to consumers.

Distribution Feeder - A supply line at lower voltages that originates at the power supply source, usually a terminal that supplies power to the customer.

Distribution Station – Transfers power from the transmission system to the distribution system of an area. Distribution stations transform voltages to a level suitable for distribution out from the terminal station for delivery to out customers.

DLP – Deer Lake Power

DRP – Disaster Recovery Plan

ECC – See Energy Control Center

EERP - Environmental Emergency Response Plan

EFOR – Equivalent Forced Outage Rate

EMS – See Energy Management System

EOC – Executive on Call

ERT – Emergency Response Team

Energy (or consumption) - The total amount of electricity that can be supplied throughout the year. In the home, the amount of energy used is measured in kilowatt-hours (kWh). The quantity of power produced by a generating station over a period of time is measured in megawatt-hours (MWh).

Energy Control Center (ECC) – The flow of electricity through Newfoundland and Labrador's power grid is controlled and monitored from the ECC. Using a modern management system, the ECC monitors and controls the flow of electricity from Hydro's various sources across the transmission system power grid throughout Newfoundland and Labrador.

Energy Management System (EMS) – a modern system used by the ECC to optimize system performance and reliability. This system allows operators to monitor the condition and the status of all interconnected equipment on the main power grid.

EPRI – Electric Power Research Institute

Fault – A general term to describe an electrical equipment failure, generally leading to an outage.

FD – See Forced Draft Fan

Forced Draft (FD) Fan– Supply the air necessary to support fuel combustion in thermal power plants.

Frazil Ice – Soft ice formed by the accumulation of ice crystals in water. It resembles slush and has the appearance of being slightly shinny when seen on the surface of water. The formation of frazil ice can restrict intake flows thereby reducing hydroelectric generation.

GDP – See Gross Domestic Product

Generator – a machine that converts one form of energy into another. In electricity generation, a generator is used to convert mechanical energy into electrical energy.

Generating Plant – an industrial facility for the generation of electric power.

Gigawatt Hour (GW h) - One billion watt hours or one million kilowatt-hours. A measure of electricity usage by homes and businesses. The energy supplied to all customers is measured in gigawatt-hours.

Gross Domestic Product (GDP) – The total value of goods and services produced in Canada. GDP measured in constant dollars is defined as Real GDP.

GS – Generating Station

GT – Gas Turbine

GWh – See Gigawatt Hour

HP – Hydro Place

HND TS – Hardwoods Terminal Station

HRD/HTGS – Holyrood Thermal Generating Station

HVdc – High Voltage Direct Current

Hydroelectric Generation - Production of electricity through the use of turbines propelled by falling water which is connected to a generator.

IT – Information Technology

IVR – Interactive Voice Response

Island Interconnected System – A series of transmission lines interconnecting various generating sources on the island portion of the province. There are an estimated 264,000 customers connected to this electricity system. Power is supplied through a combination of hydroelectric, thermal, Wind and diesel generation.

Isolated Diesel Communities – Communities that are not interconnected to the Provincial Generation and Transmission grid, which have their power generated and supplied by diesel generation. Approximately 4500 customers living in rural isolated communities within the province are provided electricity through the use of diesel generation.

Jacking Oil Pump – Pump used to supply high pressure oil for the lubrication of a turbine generator.

JDE – JD Edwards

Kilovolt (kV) - One thousand volts.

Kilowatt (kW) - One thousand watts; the commercial unit of measurement of electric power. A kilowatt is the flow of electricity required to light ten 100-watt light bulbs.

Kilowatt Hour (kWh) - One thousand watts used for a period of one hour; the basic unit of measurement of electric energy. The average electrically-heated home on the island of Newfoundland consumes about 18,200 kWh per year.

KV – See Kilovolt

KW- See Kilowatt

KWh – See Kilowatt Hour

Labrador Interconnected System – A series of transmission lines interconnecting various generating sources on the Labrador portion of the province. Approximately 10,500 customers in this area benefit from hydroelectricity as their source of power generation.

Lightning Arrestor – Device used on electrical power systems to protect the insulation and conductors of the system from the damaging effects of lightning. It will absorb and dissipate the energy from a lightening strike so as not to interrupt the normal operation of the system.

Load -The amount of electricity required to meet customer demand at any moment. The load profile fluctuations depend on electricity use throughout any given day.

Load Forecast - The expected load requirements that an electricity system will have to meet in future years.

LOLH – See Loss of Load Hours

LOLP – See Loss of Load Probability

Loss of Load Hours (LOLH) – A probabilistic assessment of the level of unserved load at time of peak, due to insufficient generation.

Loss of Load Probability (LOLP) – A measure of the probability that a system demand will exceed capacity during a given period, often expressed as the estimated number of days over a long period, frequently 10 years or the life of the system

Manitoba Hydro International Inc. (MHI) – Wholly owned subsidiary of Manitoba Hydro, one of the largest and longest-standing electric power and gas utilities in Canada.

Maximum Continuous Rating (MCR) – The gross maximum electrical output, measured in megawatts, for which a generating unit has been designed and/or has been shown capable of producing continuously.

MCR – See Maximum Continuous Rating

Megawatt (MW) - One million watts; one thousand kilowatts. A unit commonly used to measure both the capacity of generating stations and the rate at which energy can be delivered.

MHI – See Manitoba Hydro International Inc.

MW – See Megawatt

n-1 Criteria – Management criteria such that generation assets are managed so that they are able to continue to operate normally in the event of the unplanned availability of the largest available generating unit in the company's operations.

Newfoundland and Labrador Hydro (NLH) – Provincial Crown Corporation that is the primary supplier of electricity in the province of Newfoundland and Labrador.

Newfoundland Power (NP) – Primary retailer of electric power in Newfoundland and Labrador.

NLH – See Newfoundland and Labrador Hydro

NP – See Newfoundland Power

O&M – Operation and Maintenance

Operating costs - includes fixed and variable operating and maintenance costs, excludes capital cost.

OEM – Original Equipment Manufacturer

OPD TS – Oxen Pond Terminal Station

OPLF – Medium-Term Planning Forecast

P&C – See Protection and Control Systems

P&P – Pulp and Paper

Peak Demand - The maximum power demand registered by a customer, group of customers or a system in a stated period of time. The value may be the maximum instantaneous load or more, usually the average load over a designated interval of time, such as one hour, and is normally stated in kilowatt or megawatts.

PETS – See Project Execution and Technical Services

PLF – Long Term Planning Forecast

PM – See Preventative Maintenance

PPA – Power Purchase Agreements

Preventative Maintenance (PM) – maintenance activities, including testing, measuring, adjusting and the replacement of parts, performed specifically to prevent faults from occurring.

Project Execution and Technical Services (PETS) – Division of Nalcor that takes a strategic approach to the management and delivery of capital and operating projects, all safely executed within an effective, quality management framework. This high-performance project management and technical services team is dedicated to providing the best level of support possible to Nalcor's operating businesses.

Protection and Control Systems (P&C) - A collection of devices in terminal stations and generating plants that monitor the flow of electricity, operate switchgear and control generators. Protection and Control devices work together to ensure electricity is generated and transmitted safely and reliably.

Protective Relays - Monitor the voltage and current and isolate problem areas when an electrical fault or disturbance is sensed to prevent further damage. These devices can perform a variety of protective functions depending on the nature of disturbance detected.

PUB – See Public Utilities Board

Public Utilities Board (PUB) – Independent, regulatory body responsible for the regulation of electric utilities in the province of Newfoundland and Labrador to ensure rates charged are just and reasonable, and that the service provided is safe and reliable.

Reactor – An electrical component used to oppose rapid changes in current. Generally installed in motor driven equipment to limit starting current and provide protection for the equipment's motor.

Reliability - A measure of the adequacy and security of electric service. Adequacy refers to the existence of sufficient facilities in the system to satisfy the load demand and system operational constraints. Security refers to the system's ability to respond to short-term disturbances in the system.

Remote Terminal Units (RTU) – In SCADA systems, the device is used in remote locations to collect and transmit data. This device is capable of two way communication with a central or master station in order to implement processes.

RFI – Request for Information

RTU – See Remote Terminal Unit

SCADA – See Supervisory Control and Data Acquisition

SOE – Sequence of Events

SSD TS – Sunnyside Terminal Station

Supervisory Control and Data Acquisition (SCADA) – A computer controlled system that monitors and controls industrial processes that exist in the physical world.

Switchgear – Combination of electrical disconnect switches, fuses or circuit breakers used to control, protect and isolate electrical equipment.

Synchronous Condenser –A device used to adjust conditions on the transmission grid. The condenser operates similar to a large electric motor with the shaft of the motor spinning freely. This prevents the condenser from converting power and allows it to adjust the grid's voltage.

T&D – Transmission and Distribution

TapRooT Process – A systematic process, consisting of process flows, software, and training for investigating and determining the root causes of problems.

Terawatt Hours (TW h) - A unit of bulk energy; 1,000,000,000 kilowatt hours.

Terminal Station (TS) – Termination points at the end of a transmission system used to transform the transmission voltages to distribution voltages for distribution to the customer.

TL – See Transmission Line

Transformer – An electromagnetic device for changing the voltage of alternating electricity.

Transmission – The process of transporting electric energy in bulk on high voltage lines from the generating facility to various terminal stations where the voltage can be transformed for distribution to the customer.

Transmission and Rural Operations (TRO) – Division of Newfoundland and Labrador Hydro responsible for the operation and maintenance of all Hydro transmission and distribution systems, three gas turbines, one frequency converter, one mini-hydro plant and 25 diesel plants.

Transmission Line (TL) – A cable or other system of conductors that transfers electricity from one location to another.

Transmission System – A combination of wires, structures and right a ways, that transport electric energy in bulk on high voltage lines from the generating facility to various terminal stations where the voltage can be transformed for distribution to the customer.

TRO – See Transmission and Rural Operations

TS – See Terminal Station

Turbine – a rotary mechanical device that extracts energy from a fluid flow and converts it into useful electricity.

TWh – See Terrawatt Hour

UPS – Uninterrupted Power Supply

Voltage and Volts - The pressure pushing a number of electrons (current) along a transmission or distribution line is called the voltage, which is measured in volts.

Voltage Control – A generic industry term used to describe the equipment added to the electrical system to maintain system voltage levels within an acceptable bandwidth or range.

Voltage Regulator – An electromechanical mechanism or electronic component designed to automatically maintain a constant voltage. In an electric power distribution system voltage regulators may be installed at a substation or along distribution lines so that all customers receive steady voltage independent of how much power is drawn from the line.

Voltage Support – A generic industry term used to describe equipment added to the electrical system to maintain minimum acceptable voltage levels throughout the system.

Watt - A derived unit of power. Watts measure the rate of energy conversion.

WAV TS – Western Avalon Terminal Station

WCF – See Weight Capability Factor

Weighted Capability Factor (WCF) – a reliability key performance indicator for generation assets. The WCF measures the percentage of the time that a unit or a group of units is available to supply power at maximum continuous generating capacity.

NEWFOUNDLAND AND LABRADOR HYDRO

Table of Concordance

TABLE OF CONCORDANCE

Public Utility Board Request	Location in Newfoundland and Labrador Hydro's Reports
1. Events	
(a) A detailed timeline including all relevant actions and occurrences before and after each system perturbation.	See Schedules 1 and 2 of Hydro's "A Review of Supply Disruptions and Rotating Outages: January 2-8, 2014"; see also Appendix 1 of the Emergency Response and Restoration Report and Section 4 of each of the Transmission Availability, Root Cause, External Protection Review, Coordination and Communication with Customers, Technology and Communications Infrastructure, and Generation Availability Reports, and Appendix A of the Generation Availability Report.
(b) For major sub-events, such as transformer or breaker failure, operator errors, or relaying inadequacies, please describe that sub-event in detail.	See the Root Cause, External Protection Review and Transmission Availability Reports.
(c) Explain operating, equipment, procedural, or other problems encountered during the event or in the recovery efforts.	See the Root Cause, External Protection Review, Transmission Availability and Emergency Response and Restoration Reports, and Appendices B-E of the Generation Availability Report.
(d) Availability of generating units for the winter season.	See the Generation Availability Report in general and Appendix A of the Report in particular.
(e) Results of Root Cause analyses completed.	See the Root Cause Report.
(f) Specifically discuss any 2014 problems that were similar to or common to the January 2013 events, including failure of the same or similar equipment and similar failures of protective schemes. In such cases, describe remedial actions taken in 2013 and how such actions mitigated or otherwise affected the 2014 events.	See Remedial Actions from the January 11, 2013 System Events.
(g) Provide any reports describing the January 2013 event, including material as requested above.	See binder entitled "Events of January 2013"

Public Utility Board Request	Location in Newfoundland and Labrador Hydro's Reports
2. Response	
(a) Rotating outage process, execution, prioritization, and notice.	See the Emergency Response and Restoration Report and Section 4.1 of the Coordination and Communication with Customers Report; see also Appendix A of the Generation Availability Report identifying utilization of Hydro's Generation Loading Sequence and Generation Shortages Protocol.
(b) Communications with Industrial, Commercial, and Domestic customers.	See Sections 3.2, 3.3, 4.2, 4.3, 5.2 and 5.3 of the Coordination and Communication with Customers Report.
(c) Communication and coordination between the utilities.	See Sections 2.1, 3.1, 4.1 and 5.1 of the Coordination and Communication with Customers Report.
(d) Outage response plans.	See Appendices 1, 7, 8, 9, 10 and 11 of the Coordination and Communication with Customers Report and Section 3 of the Emergency Response and Restoration Report.
3. Assurances	
(a) Discussion of system readiness up to and including 2014-16.	See the Generation and Reserve Planning Report; see also Ventyx's Planning Process Review Report and Section 3.4 of the Generation Availability Report.
(b) Evaluation of the adequacy of supply to meet the 2014-16 winter peak.	See the Generation and Reserve Planning Report; see also Ventyx's Planning Process Review Report and Section 3.4 of the Generation Availability Report.
(c) Actions that have been taken to assure reliability in 2014-16.	See Section 5.2 of Hydro's "A Review of Supply Disruptions and Rotating Outages: January 2-8, 2014" Report.
(d) Actions that are planned in the months ahead to assure adequacy and reliability over 2014-16 including available alternatives. Include explanation of the actions planned, their cost, timetable, and expected impact on reliability.	See Section 5.2 and Section 6 of Hydro's "A Review of Supply Disruptions and Rotating Outages: January 2-8, 2014" Report, Section 5 of the Generation Availability Report and Section 3.5 of the Generation and Reserve Planning Report.

Public Utility Board Request	**Location in Newfoundland and Labrador Hydro's Reports**
4. Risks and Vulnerabilities	
(a) Discuss potential risks that might lead to significant outages over 2014-16.	See Section 5 of each of the Transmission Availability Report, External Protection Review and Generation Availability Report.
(b) Provide any actions planned to mitigate the events noted in 4(a) above.	See Section 5 of each of the Transmission Availability Report, External Protection Review and Generation Availability Reports; see also Section 3.5 of the Generation and Reserve Planning Report and section 5.2 of Hydro's Review of Supply Disruptions and Rotating Outages Report.
5. Ongoing Analysis	
(a) Report on all current and future planned activities aimed at further investigating the supply issues and power outages of December 2013 – January 2014 or actions planned or being considered in relation to the events. Include the name or organization managing the study, its current status and forecasted completion.	See Section 5.2 of Hydro's "A Review of Supply Disruptions and Rotating Outages: January 2-8, 2014" Report; see also the Root Cause Report and Section 6 of each of the Asset Management Strategy & Practices, Transmission Availability and External Protection Review Reports, and Section 5 of each of the Generation Availability, Technology and Communications Infrastructure and Emergency Response and Restoration Reports.
6. Customer Input	
(a) Provide the results of any customer surveys or other efforts to determine perceptions and opinions regarding the events of January 2014 or subsequent utility performance.	See Section 5.3.1 and Appendices 2, 3 and 4 of the Coordination and Communication with Customers Report.

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* Note as well that Hydro's Review of Supply Disruptions and Rotating Outages Report summarizes many of the issues noted above as being more particularly and fully dealt with in the identified Focus Area Reports.

NEWFOUNDLAND AND LABRADOR HYDRO

Sequence of Events
Leading up to Sunnyside Transformer Fault on January 4, 2014

February 2014

Table 1: Events leading up to Sunnyside Transformer Fault - January 4, 2014

Date	Time	Event
Jun. 1, 2013	**12:00**	The Stephenville Gas Turbine de-rated by 25 MW due to excessive heat build-up in the B turbine module during operation, resulting from the poor condition of the insulating blankets around the turbine and exhaust stack.
Oct. 3, 2013	**08:00**	Hardwoods Gas Turbine removed from service for alternator overhaul. Scheduled completion date was December 19, 2013.
Dec. 11, 2013		During testing at Hardwoods Gas Turbine on December 10, a jacking oil pump failed. The pump on the unit at Stephenville Gas Turbine was temporarily removed and installed at Hardwoods, causing the Stephenville unit to become unavailable while a replacement pump was obtained and installed.
Dec. 14, 2013		A new record system demand of 1,501 MW was supplied.
Dec. 15, 2013	**01:20**	Significant frazil ice accumulation affected the Exploits generation at Grand Falls. Plant production reduced from 63 MW to 38 MW (by 25 MW).
Dec. 16, 2013		Granite Canal Generating Station reduced to 32 MW due to axial vibration.
Dec. 21, 2013	**14:00**	Hardwoods Gas Turbine unavailable, suspected due to the failure of a three-way fuel valve associated with Engine A. The failure occurred during commissioning of the new alternator, following a refurbishment undertaken during the fall.
Dec. 23, 2013	**20:21**	Stephenville Gas Turbine restored to 25 MW with the installation of a new jacking pump to replace the old pump, which was removed on December 11 and sent to Hardwoods. The remaining 25 MW of capacity was pending the delivery of new insulating blankets, scheduled for early January 2014.
Dec. 25, 2013		Holyrood Unit 2 de-rated (by 25 MW) to 142 MW due to a broken control valve.
Dec. 26, 2013	**06:00**	Holyrood Unit 3 de-rated (by 100 MW) to 50 MW due to a failure of a forced draft (FD) fan motor.

Date	Time	Event
		Total unavailable generation at this time is approximately 233 MW. Implemented generation loading sequence generation shortages protocol up to step eight (with the exception of step seven). A copy of this protocol is at the end of this Sequence of Events. Communication continued with Newfoundland Power (NP) as to the status of generation assets, load forecasts, and protocols. Communications occurred internally to ensure awareness of the situation. Supply and demand at peak. Demand: 1385 MW Supply: 1426 MW
Dec. 27, 2013		Generation loading sequence generation shortages protocol was not required. Communication continued with NP as to the status of generation assets, load forecasts and protocols. Supply and Demand at Peak. Demand: 1331 MW Supply: 1456 MW
Dec. 28, 2013	**06:34**	Bay d'Espoir Unit 2 was removed from service due to air supply issue with circuit breaker B1T2. The unit was restored at 1138 hours.
Dec. 28, 2013		Generation loading sequence generation shortages protocol was not required. Forecast peak for December 29 of 1410 MW. This was communicated to NP. Preparations were made between both utilities to prepare, as per shortage protocol. A customer conservation message was discussed as a potential requirement for December 29. The decision was to be made early on December 29. Supply and demand at peak. Demand: 1354 MW Supply: 1456 MW
Dec. 29, 2013		The Stephenville Gas Turbine failed to start initially. The unit was successfully started at 2224 hours. Implemented generation loading sequence generation shortages protocol up to step 13; including asking Corner Brook Pulp and Paper (CBPP) to shed processing load. Continued to discuss the potential of issuing a public conservation message but determined it was not required. Forecast peak for December 30 of 1420 MW. Continued communication with NP regarding the continuing need to implement the Generation

Date	Time	Event
		Loading Sequence Generation Shortages protocol.
	16:35	Implemented the Generation Loading Sequence Generation Shortage Protocol steps to start NP standby generation, implement NP voltage reductions and call on curtailable customer.
	17:08	Received first assistance from CBPP (28 MW) Supply and Demand at Peak. Demand: 1425 MW Supply: 1470 MW Determined that immediate resolution of Holyrood and Hardwoods generation issues were not possible.
Dec. 30, 2013		Implemented Generation Loading Sequence Generation Shortage protocol up to step 13; This included asking CBPP to shed approximately 30 MW of load in the morning and 52 MW in the evening. There was an internal meeting held to discuss progress on generation and preparations going forward. Discussions were initiated with CBPP regarding a more formal capacity assistance agreement. Forecast peak for December 31 of 1400 MW. Continued communication with NP regarding the continuing need to implement the Generation Loading Sequence Generation Shortage protocol. Supply and Demand at Peak. Demand: 1417 MW (morning) Demand: 1417 MW (evening) Supply: 1458 MW A review of the weather forecasts highlighted that January 2-3 demand levels are were expected to be high. Generation Loading Sequence Generation Shortage protocol not required.
Dec. 31, 2013		A short- term capacity assistance agreement was reached with CBPP for 20, 40 or 60 MW blocks of power. Forecast peak for January 1 of 1450 MW. Continued communication with NP regarding the continuing need to implement the Generation Loading Sequence Generation Shortage protocol.

Date	Time	Event
		The Public Utilities Board was notified of extended capacity issues with the Stephenville Gas Turbine, Hardwoods Gas Turbine and Holyrood Unit 3.
Dec. 31, 2013		Supply and Demand at Peak. Demand: 1393 MW Supply: 1453 MW Implemented Generation Loading Sequence Generation Shortage protocol up to step 13. This included capacity assistance from CBPP for 40 MW during peak.
Jan. 1, 2014		Forecast peak for January 2 of 1500 MW. Continued communication with NP regarding the continuing need to implement the Generation Loading Sequence Generation Shortage protocol. Supply and Demand at Peak. Demand: 1440 MW Supply: 1484 MW
Jan. 2, 2014	**08:00**	A conservation request discussion was initiated with NP in the early morning. The short-term forecast indicated that the evening peak would outstrip available supply.
	14:00	Conservation request issued to all island customers.
	16:13	NP started feeder interruptions. See attached slide for details of the feeder interruptions from January 2 to January 8.
	16:34	Granite Canal unit tripped with a loss of 33 MW.
	16:56	Newfoundland and Labrador Hydro (Hydro) started feeder interruptions. See attached slide for details of the feeder interruptions from January 2 to January 8. Peak Demand supplied 1493 MW at 16:15 hours.
Jan 3, 2014	**12:06**	Unit 2 restored to 165 MW, with only a minor de-rating of 5 MW.

NP – Feeder Interruptions

Date	Time	Feeder Rotations	Average Duration (minutes)
Thursday January 2, 2014	4:13 pm to 10:45 pm	77	88
Friday January 3, 2014	6:57 am to 7:36 pm	141	44
Sunday January 5, 2014	7:23 am to 8:29 pm	158	54
Monday January 6, 2014	5:17 am to 10:48 am	39	47
Wednesday January 8, 2014	3:23 pm to 5:42 pm	32	25

NLH – Feeder Interruptions

Date	Time	Feeder Rotations	Average Duration (minutes)
Thursday January 2, 2014	4:56 pm to 10:50 pm	6	30
Friday January 3, 2014	7:00 am to 7:30 pm	25	30
Sunday January 5, 2014	5:04 pm to 7:03 pm	5	60
Wednesday January 8, 2014	3:32 pm to 4:30 pm	3	30

newfoundland labrador hydro
a nalcor energy company

SYSTEM OPERATING INSTRUCTION

STATION:	GENERAL	**Inst. No.**	T-001
TITLE:	GENERATION LOADING SEQUENCE AND GENERATION SHORTAGES*, **	**Rev. No.**	07
		Page 1	**of** 2

INTRODUCTION

In the event of a system generation shortage, the following guidelines shall be followed in the sequence outlined in order to minimize outages to customers:

PROCEDURE

A. Normal Generation Loading Sequence

1. Bring on line all available Hydro hydroelectric generators and load them to near their full capacity.

2. Request Newfoundland Power to maximize their hydro production.

3. Make a Capacity Request of Deer Lake Power to maximize their hydroelectric generation.

4. Request Non-Utility Generators to maximize their hydro production.

5. Increase Holyrood production to near full capacity.

6. Notify customers taking non-firm power and energy that if they continue to take non-firm power, the energy will be charged at higher standby generation rates.

7. Ask Newfoundland Power to curtail any interruptible loads available.

8. Start and load standby generators, both Hydro and Newfoundland Power units, in order of increasing average energy production cost with due consideration for unit start-up time.

PREPARED BY:	**APPROVED/CHECKED BY:**	**ISSUED DATE:** 1992-07-16
Robert Butler		**REV. DATE:** 2009-04-29

newfoundland labrador hydro a nalcor energy company

SYSTEM OPERATING INSTRUCTION

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		Page 2	**of** 2

PROCEDURE (cont'd.)

9. Cancel all non-firm power delivery to customers and ensure all industrial customers are within contract limits.

If load is still increasing and it is apparent that a generation shortage may occur, proceed as follows:

10. Ensure that steps A1 to A9 above have been followed and implemented.

11. Inform Newfoundland Power of Hydro's need to reduce supply voltage at Hardwoods and Oxen Pond and other delivery points to minimum levels to facilitate load reduction. Begin voltage reduction.

12. Request industrial customers to shed non-essential loads and inform them of system conditions.

13. Request industrial customers to shed additional load.

14. Request Newfoundland Power to shed load by rotating feeders. At the same time, shed load by rotating feeders in Hydro's Rural areas where feeder control exists.

Note:

Generation from Wind Farms may shutdown with little notice.

* Part of the Environmental Plan
** Part of the Emergency Response Plan

PREPARED BY:	**APPROVED/CHECKED BY:**	**ISSUED DATE:** 1992-07-16
Robert Butler		**REV. DATE:** 2009-04-29

NEWFOUNDLAND AND LABRADOR HYDRO

Sequence of Events
Following Sunnyside Transformer Fault on January 4, 2014

February 2014

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Events Following SSD Transformer Fault - January 4, 2014

Date	Time	Event
Jan. 4, 2014		Weather forecast for blizzard conditions and heavy snowfall; crews prepared for storm response.
	08:00	Crews dispatched to major terminal stations on the Avalon. Remote hydroelectric plants staffed by operators, and the road to the Upper Salmon plant was maintained open.
	09:05:34	Fault detected in transformer T1 at Sunnyside (SSD). The SSD transformer T1 lockout protection operated resulting in following breaker operations: SSD L109T4 open SSD B3T4 open SSD B1L02 open SSD B2T1 open Four of five breakers for T1 operate, breaker B1L03 failed to open, keeping the 230 kV Bus B1 and transformer T1 energized from TL203. Fault evolved and protection circuits at multiple locations sensed the fault.
	09:05:35	SSD disconnect switch B1T1 in-transit alarm, indicated the disconnect switch had started to open.
	09:05:36	The Paradise River generating unit tripped, with a loss of 8 MW. As a result of the failure of SSD B1L03 to open and clear the T1 fault, the primary one, primary two and backup protection operated on transmission line TL203 at the Western Avalon Terminal Station (WAV). The backup protection also operated for transmission line TL203 at SSD. The following breakers opened for this event: SSD L03L06 open WAV L01L03 open WAV L03L17 open

Date	Time	Event
		TL203 was open at the WAV end and SSD Bus B1 and transformer T1 were de-energized. Backup protection also operated on transmission line TL237 at Come by Chance (CBC) and WAV. The following breakers opened for this event: CBC B1B2 open WAV L01L37 open Circuit breaker B1L37 at WAV appeared to have been delayed in opening by two seconds for the protection trip. **Transmission Lines TL203 (SSD – WAV) and TL237 (CBC – WAV) were out of service and the Avalon was isolated from the rest of the power system. Bus B1 and Transformer T1 at the Come By Chance TS were still energized. The Holyrood Generating Plant remained on-line, momentarily.**
	09:05:37	Normal Newfoundland Power supply to Hydro Place was lost; Hydro's EMS switched to battery power.
	09:05:37	Units at Holyrood cannot supply the load. Holyrood Units 2 and 3 are tripped and isolated from the system by unit breakers. Unit 1 trip is initiated and unit breaker B1B11 opened three phases. Unit breaker B1L17 opened only on two phases during the trip. Backup protection operated on transmission line TL242 at Hardwoods Terminal Station (HWD). Breaker B1L42 opened at HWD. Backup protection operated on transmission line TL218 at Oxen Pond Terminal Station (OPD). Breaker B1L18 opened at OPD. Holyrood Unit 3 was isolated from the system. **Transmission Lines TL203 (SSD – WAV) and TL237 (CBC – WAV) were out of service and the Holyrood Generating Plant was shut down and isolated. The 138 kV and 66 kV transmission had also tripped via NP lines 64L, 86L, 39L from WAV to HRD.**

Date	Time	Event
	09:05:38	Breaker B1L37 at WAV opened, closed and then re-opened in a three second period, an indication that the breaker operated only on two phases.
	09:05:38	Star Lake generating plant tripped with the loss of 18 MW and Stephenville Gas Turbine tripped.
	09:05:41	Cat Arm and Hinds Lake generating plants tripped with a loss of 205 MW of generation.
	09:05:41	SSD disconnect switch B1T1 was fully open, providing full isolation of transformer T1.
	09:05:45	Diesel G1 at Hydro Place on-line, re-storing AC supply.
	09:05:45	Hydro's EMS switched to diesel supply.
	09:09:45	EMS indication for breaker B2L42 at Holyrood toggled between open and closed multiple times, likely making its actual state unclear to the ECC operators.
	09:13	Upper Salmon generating plant tripped with the loss of 88 MW.
	09:27	Breaker B1B2 at Come By Chance closed by the ECC, marking the start of restoration phase and energizing transmission line TL237 to Western Avalon.
	09:41	Attempts to energize Bus B1 at WAV from line TL237. Line breaker B1L37 closed, but tripped again 1.2 seconds later. It was later determined that only two phases of the breaker had closed and there was a phase disagreement trip, momentarily energizing Busses B1 and B3, the WAV transformers, and transmission line TL208 to Vale, all on two phases. A Gas/Oil/Temperature alarm was received for transformer T5. ECC opened WAV breaker B1L08 to isolate TL208 and attempted to close B1L37 again, with the same result. Another Gas/Oil/Temperature alarm is received for T5.
	09:51	WAV circuit breaker L01L37 was closed by ECC, energizing a 230 KV ring Bus section at WAV, transmission line TL201 and the HWD terminal station.

Date	Time	Event
	09:57	Stephenville Gas Turbine in service at 25 MW.
	10:08	Upper Salmon generating plant in service at 88 MW.
	10:14	Granite Canal generating plant in service at 40 MW.
		ECC attempted to close breaker B2L42 at HWD to energize TL242 into Holyrood and restore station service. This energized HRD Bus B12 and, since unit breaker B1L17 had failed during the earlier events and remained closed on one phase, this resulted in a single-phase energizing of Unit 1 transformer T1. Protection circuits for TL242 operated at both HWD and Holyrood. Additional breakers were opened by ECC to provide for further isolation of the HRD TS.
	10:24	Holyrood station service is restored via transmission line TL242 (HWD – HRD) and HRD transformer T10.
	10:26	Holyrood unit disconnect switches B1T1 and B2T2 were opened by the HRD operators.
	10:38	Hydro Place diesel unit G1 tripped offline due to high temperature. There is no power at Hydro Place and EMS switched to battery power.
	10:41	Breaker B1L36 is closed at HWD, restoring transmission line TL236 (HWD – OPD) and OPD TS.
	10:41	ECC closed breaker B3L47 at Deer Lake, energizing transmission line TL247 and starting the process of restoring Cat Arm generating units.
	10:57	Breaker B1L03 at SSD, the breaker that failed to open during the T1 fault, opens un-commanded.
	11:03	The beginning of a 43-minute outage to the ECC, EMS. The outage resulted from a short power interruption (13 seconds), upon the loss of primary supply (Newfoundland Power), the standby diesels and the UPS system. The system was recovered and re-established at 11:46.
	12:00	SSD transformer T1 isolated from the system via disconnect switches. Transformer reported to be still on fire.

Date	Time	Event
	12:13	Three additional, but unsuccessful, attempts to close breaker B1L37 at WAV to restore 230 Busses B1 and B3. Similar to previous attempts the breaker closed only momentarily and at least one T5 transformer Gas/Oil/Temperature alarm was received. At 12:15 the ECC closed WAV breaker B1L17.
	12:18	Cat Arm Unit 2 in service at 65 MW.
	12:22	ECC closed breakers L03L17 and L01L03 at WAV, energizing Busses B1 and B3 from TL237. Due to previous actions this also energized transmission lines TL203 to SSD and TL217 to HRD. WAV transformer T5 lockout protection operated after restoration of Busses B1 and B3, isolating the transformer from the system via WAV breaker B1B3 and transformer disconnects B3T5 and B4T5. It was later determined there was an internal failure of the transformer tap changer. WAV busses B1 (230 KV) and B2 (66 KV) were restored.
	12:23	ECC restores TL217 (WAV - HRD).
	12:30	ECC restores TL218 (HRD - OPD).
	12:56	Cat Arm Unit 1 in service at 65 MW.
	12:57	Bus B1 and Transformer T4 are re-energized at SSD, re-establishing station service and restoring the breaker compressed air system.
	12:58	Switching at SSD to restore the load side of transformer T4 (138 KV). Breaker B3T4 closed by ECC, resulting in the operation of the Bus B1 lockout switch at SSD, initiated by the transformer disconnect switch, B1T4, opening under load and resulted in an arcing fault. Breakers B3T4 and B1L02 tripped. Breaker B1L03 had been previously isolated. Attempt to restore T4 failed. Impact was confined to the Sunnyside Station. Investigation determined the Bus B1 differential protection operated upon closure of B3T4, likely caused by the current transformers and

Date	Time	Event
		wiring on transformer T1 having been destroyed by the transformer fire.
	14:10	Stephenville Gas Turbine off line.
	14:28	Stephenville Gas Turbine in service at 25 MW.
	14:36	After a couple of unsuccessful attempts, the SSD transformer T4 disconnect B1T4 is closed.
	14:37	Circuit breaker B4L64 closed at WAV, restoring 64L and the 138 kV supply to Newfoundland Power on the Avalon.
	14:40	ECC closed breaker L03L06 at SSD, restoring both ends of TL203 (SSD – WAV).
	14:41	The SSD 230 KV Bus B1 was re-energized by ECC via breaker B1L02, which also energized transformer T4. SSD Station service is restored.
	15:12	Hinds Lake unit restarted and loaded to 75 MW. There were considerable issues with the unit breaker B1G1.
	15:25	Circuit breaker B8L39 was closed at HRD, restoring the 138 kV loop from WAV to HRD. **All transmission to the Avalon was restored.**
	15:33:26	A second attempt was made to restore the load side of SSD transformer T4 (138 KV). Breaker B3T4 closed by ECC and again resulted in the opening of the transformer disconnect switch B1T4 under load. The protection at Sunnyside did not operate as expected to clear the arcing fault, which resulted in the operation of the protection on the remote ends of transmission lines TL202 and TL206 at Bay d'Espoir (BDE).
	15:33:32	Breakers B11L06 and L06L34 opened at BDE to trip transmission line TL206 as expected.
	15:33:33	Protection at BDE did not operate to trip transmission line TL202 as expected. Breakers B3B4 and B4B5 would ordinarily trip TL202 at the

Date	Time	Event
		BDE end, but were slow in operating. Lockout protection operated and resulted in a trip of breakers B5B6, B3T5, B3T6, and B2B3. This resulted in a loss of TL204 (BDE – Stoney Brook), and BDE Units 5 and 6 (loss of 150 MW of generation). Breakers L02L07 and B1L02 tripped to isolate TL202 at SSD. **There was a loss of supply from BDE to Sunnyside and the Avalon Peninsula, including Come By Chance. The Auto Restoration Scheme (ARS) was in a disabled state following the return of the EMS at 11:46.**
	15:33:43	Cat Arm Units 1 and 2 tripped off-line with a loss of 130 MW of generation.
	15:37	ECC initiates a close of breaker B11L06 to close TL206 at the BDE end. The line was already closed at the SSD end. This action energized the terminal stations east of SSD.
	15:38	Primary one protection operated on the following transmission lines: TL201 – HWD and WAV TL203 – SSD and WAV TL207 – CBC and SSD TL217 – HRD and WAV TL218 – HRD and OPD TL236 – HWD and OPD TL242 – HRD and HWD Associated line breakers opened for these line protection trips.
	15:39	ECC initiated a breaker group open at WAV. Transmission Line TL206 was restored (BDE – SSD). Power was restored to SSD TS, TL207 and North Atlantic Refining at Come by Chance.
	15:40	Circuit breaker B3T4 was opened at SSD by ECC.
	15:53	Transmission Line TL203 (SSD – WAV) and WAV TS was restored.
	15:54	Transmission Line TL201 (WAV – HWD) and HWD TS was restored.

Date	Time	Event
	16:05	BDE Unit 6 restored at 75 MW.
		Transmission Line TL236 (HWD – OPD) and OPD TS were restored.
	16:06	BDE Unit 5 restored at 75 MW.
		Cat Arm Unit 1 restored at 65 MW.
	16:09	Transmission Line TL204 (BDE – Stony Brook) restored.
	16:09	Transmission Line TL242 (HWD – HRD) and HRD TS and station service restored.
	16:10	Transmission Line TL202 (BDE – SSD) restored.
	16:14	Transmission Line TL237 (CBC – WAV) in service.
	16:19	Transmission Line TL217 (WAV – HRD) restored.
	16:26	Cat Arm Unit 2 restored at 65 MW.
		Granite Canal unit restored to 32 MW.
	16:59	Star Lake generating unit restarted and loaded to 18 MW.
	18:00	Transmission Line TL218 (OPD – HRD) restored.
	18:31	SSD Transformer T4 re-energized, restoring station service.
	20:07	Transmission Line TL219 restored, bringing grid power to Burin Peninsula, which was lost during the initial trip at 09:05.
	21:34	Holyrood Unit 2 back on-line at 165 MW (minor de-rating of 5 MW).
	21:45	The 138 kV loop from Stony Brook to SSD restored.
Jan. 5, 2014	**01:40**	Holyrood Unit 3 on-line at 50 MW. (Holyrood Unit 1 remained down due to vibration issues)

Date	Time	Event
	08:10	ECC closes breaker B1L08 at WAV to energize TL208 to Vale.
	10:40	WAV transformer T3 overload protection trip. Transmission Line 64L tripped at WAV. Outages to Newfoundland Power customers in the Bay Roberts area. Newfoundland Power circuit breaker at Bay Roberts on 39L failed with no supply available from HRD.
	10:44	Transmission Line 64L restored at WAV. Newfoundland Power customers restored.
	11:08	WAV transformer T3 overload protection trip. Outages to Newfoundland Power customers in the Bay Roberts area. Newfoundland Power circuit breaker at Bay Roberts on 39L had failed with no supply available from HRD.
	11:18	Transmission Line 64L restored at WAV. Newfoundland Power customers restored.
	21:27:34	Disconnect switch B1T1 closed at HRD, the first step before the generator is synchronized to the system.
	21:27:41	Disconnect switch B1T1 opened at HRD after the operation of the unit lockout switch on HRD Unit 1. The unit lockout switch operated on HRD Unit 2. Primary protection one and backup protection operated on Transmission Line TL217 at WAV end only. Circuit breakers B1L17 and L03L17 opened. Backup protection operated on transmission line TL218 at OPD end only. Circuit breaker B1L18 opened at OPD.
	21:27:41	Primary protection one operated on transmission line TL242 at HWD end only. Breakers B2L42 at HWD and HRD opened. Protection relay 94TS/T1 operated on transformer T1 at HRD.

Date	Time	Event
		Breaker failure lockout protection operated on the following circuit breakers at HRD. HRD B3L18 HRD B3B130 HRD B1L17 Breaker failure lockout protection operated on circuit breaker B1L17 at WAV and Bus B1 at WAV. The unit lockout switch operated on HRD Unit 3. **The St. John's area was being supplied via TL201 from WAV. Holyrood Units 2 and 3 were off-line (Unit 1 had tripped during the previous day). The 138 kV loop from WAV to HRD was not available.**
	22:19	Transmission Line TL242 (HWD – HRD) restored.
Jan. 6, 2014	**02:02**	Circuit breaker B1L17 was isolated at HRD.
	03:34	Transmission Line TL217 was energized from WAV to HRD to test for line or Bus fault. No fault was found and TL217 was restored.
	05:29	Holyrood Unit 2 back on-line at 165 MW, with a minor de-rating of 5 MW.
	05:46	Transmission Line TL218 (OPD – HRD) restored.
	07:17	HRD Unit 3 on-line at 50 MW.
Jan. 8, 2014	**15:27**	Test performed to energize HRD Bus B1. Disconnect switches B1L17-1 and B1B11-2 were opened. HRD disconnect switch B1T1 was closed. No problems detected and disconnect switch B1B11-2 was closed. Approval given to HRD plant to synchronize Unit 1 to the system.
	15:38	Holyrood Unit 1 on-line at 165 MW, with a minor de-rating of 5 MW.