Q. **Reference: Supply Cost Deferrals 2015, 2016 and 2017 Application Evidence, Page 7, lines 13-21.**

Finally, Hydro has discussed or provided information regarding its philosophy and practices to the Board in its reply to the Liberty March 4, 2015 Voltage Collapse report, throughout the testimony provided as part of Hydro's 2013 Amended GRA and Hearing, in the 2015 Cost Deferral Application, the 2016 Application for Standby Fuel Deferral Costs, the 2016 Supplementary Application for Overhaul of the Holyrood CT, in the 2017 Establishing a Robust Operational Philosophy and Enhancing Skills and Capabilities Relating to Systems Reliability and Analysis, the Monthly Energy Supply Reports, through various letters in response to Board requests, and through other capital and supplementary capital budget applications related to standby units.

Provide a list specifying all relevant excerpts from each of the references cited.

A. **May 15, 2015** Letter to the Board Re: March 4, 2015 Power Outage Report (*Power Outage/Incident Advisory 2015-H-062*"

Please refer NP-NLH-300, Attachment 1, page 3-4, answer to Q3.

> *...System security assessments of both the Island Interconnected System and the Avalon Peninsula are now performed daily based on current load forecasts for the next seven days. The assessments allow for advance coordination of primary generation, standby generation, and sources of reactive support, such as capacitor banks. These assessments are used in concert with the customer and stakeholder communications protocols described in the report.*

October 20 and 21, 2015 Transcript from 2013 Amended General Rate Application Hearing

Please refer to pages 129-140 of NP-NLH-300, Attachment 2 and pages 14-28 of NP-NLH-300, Attachment 3.

In particular:

October 20, page 131 line 18 to page 132 line 13

> *Part of our learnings from that event and you know, way to increase the reliability of the system, like we recognized, I guess, that there was an event out there waiting to happen which was essentially the Holyrood unit not being available when required and prior to, I guess, this event, we would have held off on starting the CT until it was required. But right now, I guess, part of our learnings from this event is that when we know that there's a worst case outage out there that's going to result in a customer impact during the time say and I say a customer impact, we may have -- you know, there may be an outage that results in a transmission line overload that we have to hold off customers or there may be an issue with delivery point voltages as well. So we've developed, I guess, a set of load triggers now that tell us that we will be operating the CT in advance of these outages.*

Page 132, line 23 to page 133 line 5

> *But we do have daily reliability assessments of the power system and through those assessments, we take our load forecast and we take our generation availability and based on our load forecast -- it's*

primarily an Avalon requirement. So based on our Avalon load forecast, now we have load triggers that we'll start up the CT.

October 21, page 21, lines 7-11

…following the March 4th event that we undertook a review, and at that point we realized that it was prudent to start our standby units in advance of outages that would result in a customer outage.

October 21, page 22 line 23 to page 23 line 8

…back to our March 4th event. Part of the learnings there were we developed a protocol for Avalon reserves that basically mirrors the protocol that was already in place for island reserves. So in that there's a step by step sequence that our ECC operators follow in the event that there's reserve issues on the Avalon. So they would follow that sequence and as part of that sequence would be the start up of our standby on the Avalon.

October 21, page 25 line 14 page 26 line 5

It's essentially a cost of reliably operating the power system. I would say that it's really - it's a different generating unit, but it's not a lot different than where we've been, say, in the last five or six years or seven years since we've had Holyrood reduced to minimum operation. You know, for all intents and purposes, the driver for operating Holyrood units, although there may be portions of the energy that would have been required to augment our hydro generation and storages, you know, the primary driver for operating Holyrood units for the last six or seven years has been from a *reliability standpoint as well. So that has added to increased fuel costs that have flowed through the RSP as well.*

November 12, 2015 Amended 2015 Cost Deferral Application – Schedule 3, Evidence to the Amended 2015 Cost Deferral Application

Please refer to NP-NLH-300, Attachment 4 for a copy of the Amended 2015 Cost Deferral Application. In particular, the following excerpts and Appendices are relevant to the citation provided in this question.

Page 10

The Energy Supply Cost Variance Deferral Account is forecast to have a balance of approximately $7.1 million at year-end of 2015. This balance is primarily due to variances in hydraulic and gas turbine production. Decreased hydraulic production, primarily on the Nalcor Exploits system, is being replaced by more expensive thermal generation. The replacement of low cost purchases with Holyrood generation has resulted in a significant increase in supply costs for 2015.

In addition, operational requirements have increased production at the Holyrood Combustion Turbine (Holyrood CT) in 2015. Production at the Holyrood CT is forecast to increase by approximately 20.5 GWh more than the 2015 Test Year forecast in order to increase system reliability on the Avalon Peninsula. This increased production at the Holyrood CT, in combination with lower hydraulic production at Nalcor Exploits, is the other primary driver of the forecast balance for 2015. The forecast balance of $7.1 million in this account reflects

> *the proposed cost variance threshold of $0.5 million which would accrue as a supply cost to Hydro.*
>
> *Increased production at the Holyrood CT resulted in Hydro operating in a manner that enabled more reliable service to customers throughout 2015. In addition, consistent with the operation of the RSP, levels of hydraulic production are, to a great degree, beyond management's control. Hydro submits that both sources of variance result in a material increase in the cost of providing reliable service to customers and were prudently incurred. Appendix C to this evidence provides the calculation of the forecast 2015 year-end balance in the Energy Supply Cost Variance Deferral Account.*

Appendices C & F

November 17, 2015 Response to Liberty's Report, Hydro stated the following:

> *Hydro is taking Liberty's report under advisement. Since March 4, 2015, Hydro has changed how it responds to adverse events including how it dispatches and runs generating plants. Hydro has also implemented improved internal and external communication protocols to ensure its emergency response is robust. These changes built on the significant work done following the January 2014 outage. The company will continue to move forward with its work to improve reliability for customers.*

Please refer to NP-NLH-300, Attachment 5, for a copy of the letter.

December 22, 2015 Final Reply to the Liberty March 4, 2015 Voltage Collapse report

Please refer to NP-NLH-300, Attachment 6 for a copy of Hydro's reply. In particular, the following excerpts are relevant to the citation above:

Page 3

> *Hydro has expanded its previously occurring daily reviews and reporting of capability and reserves to include a dedicated assessment of system conditions on the Avalon Peninsula. System reliability assessments of both the Island Interconnected System and the Avalon Peninsula are now performed daily, based on current load forecasts for the next seven days. The assessments allow for advance coordination of primary generation, standby generation, and sources of reactive support, such as capacitor banks.*

Page 5

> *Hydro reviewed its operating procedures and has commenced the practice of operating standby generating units (that support the Avalon) in advance of the single largest Avalon contingency, rather than starting them after the event has occurred. To support this improvement, Hydro's ECC operators are receiving daily standby generation requirement guidelines for supporting the Avalon transmission.*

Page 10

> *This previously existing objective of service continuity was further enhanced after the March 4, 2015 interruption. These*

> *enhancements are a further step forward in Hydro's approach to maintaining a reliable system. This is especially evidenced by the system and operational changes implemented in 2015 as discussed above, such as the development of the Avalon reliability assessments and procedures and placing standby generation online in advance of the single largest contingency, as opposed to after the contingency occurs.* ***This can result in increased supply costs when operating the system, but results in lower risk of customer impact and unserved energy in the event of a contingency.***

January 22, 2016 Newfoundland and Labrador Hydro — 2013 General Rate Application Final Submission — Revision 1

Please refer to NP-NLH-300, Attachment 7, page 50

> *Included in these forecast fuel costs for 2015 is the cost of operating the new Holyrood CT. In contrast to forecast production levels included in the 2015 Test Year, Hydro has been running the Holyrood CT at minimum output levels during peak periods of the day to provide enhanced system reliability. This operational practice began in 2015 in response to enhanced reliability assessments following the March 4, 2015 outage event, and has resulted in increased fuel consumption at the Holyrood CT relative to the 2015 Test Year forecast.*

February 5, 2016, Application by Newfoundland and Labrador Hydro for a 2016 Standby Fuel Deferral Account for Fuel Consumed in Combustion Turbines and Diesel Generators

Please refer to NP-NLH-300, Attachment 8 for a copy of Hydro's 2016 Application for Standby Fuel Deferral Costs. The Application in its entirety speaks to why Hydro incurred costs in excess of its 2015 Test Year standby fuel costs. In particular, it addresses the use of increased standby generation for energy due to low hydrology, load growth, and planned and unplanned outages. Specifically, Section 4.0 Reliability and Operational Resiliency states:

> *4.1 Increased Reliability*
>
> *Even under the Average Inflows scenario used in the test year, Hydro anticipates using increased Standby Generation in 2016 compared to the 2015 Test Year. Hydro operates its Standby Generation in the following situations:*
>
> *1. In advance of single largest contingencies on the Avalon[1];*
> *2. To meet spinning reserves requirements on the Island Interconnected system[1]; and*
> *3. In response to unit and transmission line outages.*
>
> *These operational practices are consistent with the findings of Liberty Consulting in their report on the events of March 4, 2015.[2]*
>
> *4.2 Increased Avalon and Energy Reserves*
>
> *There are situations when the Standby Generation units are placed online to support system requirements. In January 2016, Hydro took*

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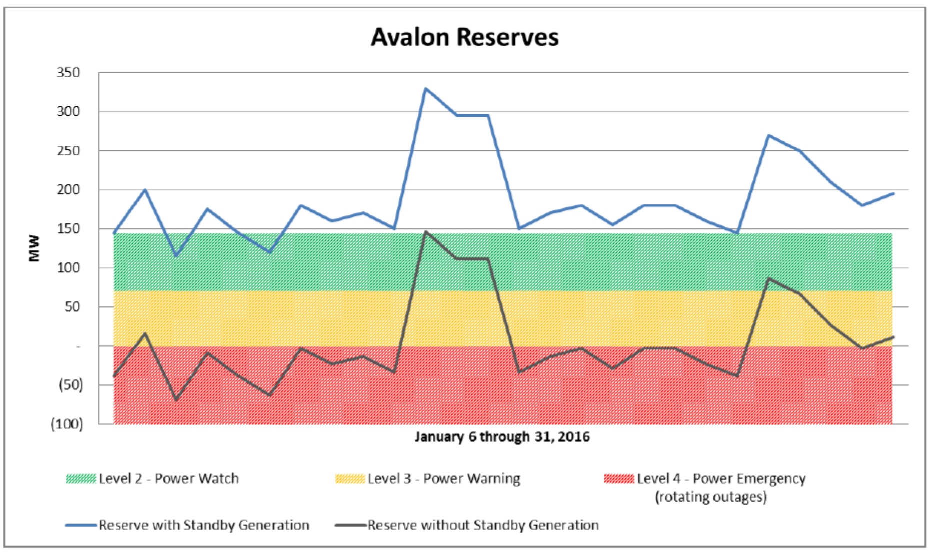
[1] NLH 2013 GRA Final Submission, page 50 reads "Included in these forecast fuel costs for 2015 is the cost of operating the new Holyrood CT. In contrast to forecast production levels included in the 2015 Test Year, Hydro has been running the Holyrood CT at minimum output levels during peak periods of the day to provide enhanced system reliability. This operational practice began in 2015 in response to enhanced reliability assessments following the March 4, 2015 outage event, and has resulted in increased fuel consumption at the Holyrood CT relative to the 2015 Test Year forecast."

[2] Liberty Consulting Review of the March 4, 2015 Voltage Collapse, Page 7 reads "Liberty continues to believe that Hydro should be significantly enhancing its capabilities to plan and manage reliability contingencies."

Unit 2 at the Holyrood TGS out of service for emergency boiler tube replacement. During this time, Hydro's Standby Generation was used to provide reliable service to customers on the Avalon Peninsula as well as to provide energy to the system. Chart 4 illustrates the overall benefit that Standby Generation provides towards reliable supply on the Avalon Peninsula during January 2016.

Chart 4



As shown in Chart 4, in the absence of running Hydro's Avalon Standby Generation, the Avalon Peninsula would have been in a Level 4 Power Emergency for the majority of January 2016 and Hydro would have instituted rolling customer outages on the Avalon. In addition to improved reliability afforded by running the Standby units, the use of Standby Generation in this manner has also injected energy into Hydro's system. This has resulted in reservoir storages which are higher than they otherwise would have been.

Supplemental Application for Combustor Inspection Major and Overhaul, August 29, 2016

Please refer to NP-NLH-300, Attachment 9 for a copy of Hydro's Supplemental Application for Combustor Inspection Major and Overhaul. In its Application, Hydro explains that usage of the Combustion Turbine was higher than anticipated at the time of its purchase, thus advancing the requirement for inspection and overhaul of the combustor. Specifically, the following excerpts highlight Hydro's operating practices for the unit and provide specific examples.

Page 8

> *After the March 4, 2015 power outage event, Hydro implemented practices and strategies which impacted the utilization of standby generation on the Island Interconnected System, especially on the Avalon Peninsula. Specifically, Hydro commenced the practice of operating standby generating units that support the Avalon in advance of Avalon transmission or generation contingencies, rather than starting them after the event has occurred[3]. This practice, in an effort to positively impact system reliability, began in late March 2015.[4]*

Page 18

> *The Holyrood CT provides several critical functions in reliably supplying customer demand requirements. It is operated to support spinning reserves on the Island Interconnected System and provides*

---

[3] Consistent with the recommendations of Liberty Consulting in the Review of the March 4, 2015 Voltage Collapse, page 7: "Liberty continues to believe that Hydro should be significantly enhancing its capabilities to plan and manage reliability contingencies."

[4] Hydro previously advised the Board of this in Response A9 of its May 15, 2015 submission to the Board answering the questions of their April 21, 2015 letter related to the March 4 events.

a critical backup in the event of a contingency such as the loss of a major generating unit or the loss of a major transmission line. The Holyrood CT also provides power to the Avalon Peninsula which is heavily reliant on the transfer of power over transmission lines outside of the Avalon Peninsula, as well as the production of power from the Holyrood Thermal Generation Station. In addition, it is used to facilitate planned generation and Avalon Peninsula transmission outages.

March 30, 2017, Establishing a Robust Operational Philosophy and Enhancing Skills and Capabilities Relating to Systems Reliability and Analysis

Please refer to NP-NLH-300, Attachment 9 for a copy of Hydro's report on Establishing a Robust Operational Philosophy and Enhancing Skills and Capabilities Relating to Systems Reliability and Analysis. This report discusses many changes Hydro has made to support the establishment of a robust operational philosophy in relation to system reliability. In particular, the following excerpts highlight Hydro's operating practices.

Page 15

In its process of improving system reliability, Hydro has started to operate standby generation in advance to cover generation or transmission outages equal to the worst case contingency (for either Island or Avalon) and to maintain Island spinning reserves. Based on reserve requirements, the Energy Control Center will operate the Hardwoods gas turbine, Holyrood combustion turbine, and Holyrood diesel standby generating units (or a combination thereof) in advance of the single largest Avalon contingency, rather than

starting them after the event has occurred. This maintains the Avalon reserve. This practice results in lower risk of customer impact and unserved energy in the event of a contingency.
For the Island, standby generation is started in advance to maintain appropriate spinning reserves. In addition to the standby generation mentioned previously, the ECC will operate the Stephenville gas turbine and the Hawkes Bay and St. Anthony diesel generators for Island spinning reserves.

To support this improvement, Hydro's ECC operators now receive daily standby generation requirements from System Operations, supporting both the Island Interconnected System and the Avalon Peninsula transmission, which allows operators to understand predicted changes to the load forecast and better plan for system continuity. The standby generation requirements are sent each morning as part of the daily system status meeting notes to the daily system status meeting participants. There is also a standby generation group email created that receives these notifications. The requirements are monitored throughout the day and if there are any changes due to load forecast changes, System Operations will send a revised standby requirement.

Appendix D, System Operating Instructions for Avalon Capability and Reserves (T-096)

May, 19, 2016 Gas Generator Engines Refurbishments – Hardwoods and Stephenville

Please refer to NP-NLH-300, Attachment 11 for a copy of Hydro's Supplemental Application for Gas Generation Engines Refurbishments at Hardwoods and Stephenville. In its Application, Hydro explains that it experienced gas generator engine failures at both Hardwoods and Stephenville, and that the availability of both plants is critical to ensure reliable service for customers in the current system configuration. Specifically, the following excerpts highlight Hydro's operating practices for the unit and provides specific examples.

Page 1

> *All three of Hydro's gas turbine plants provided significant generation to the IIS in 2016 to support reliable customer service.*

Page 4

> *The availability and reliability of the Hardwoods and Stephenville plants is critical to ensure voltage regulation of the IIS. In addition, both facilities are important for the generation of peak and emergency power.*

Page 5

> *Hardwoods provides power and reactive output to enable the reliable supply of power to the Avalon Peninsula, which is heavily reliant on the transfer of power over transmission lines from off the Avalon Peninsula, as well as the production of power from the Holyrood Thermal Generating Station. This unit provides a critical backup in the event of a contingency such as the loss of a Holyrood generating unit or loss of a major transmission line into the area.*

Page 13

The availability and reliability of the Hardwoods and Stephenville plants is critical to ensure voltage 1 regulation of the IIS, generation of peak power, emergency power and planned generation or transmission outages. Without refurbishing these engines, power generation capacity of each plant and reliability of the synchronous condensing start-up system are reduced. As such, both engines are required to provide reliability to the IIS.

This project proposes to refurbish the two failed gas generator engines in order to restore the generation capacity and reliability of the gas turbine plants and provide continued reliability support to the IIS.

July 28, 2017 Hydro 2018 Capital Budget Application, Increase Fuel and Water Treatment System Capacity, Holyrood Gas Turbine

Please refer to NP-NLH-300, Attachment 12 for a copy of Volume II Tab II of Hydro's 2018 Capital Budget Application; Increase Fuel and Water Treatment System Capacity; Holyrood Gas Turbine. In its Application, Hydro explains that, to date, operation of the Holyrood GT was materially more than forecast and that increased fuel and water treatment system capacity was required. Specifically, the following excerpts highlight Hydro's operating practices for the unit and provides specific examples.

Page i

Since that time, the gas turbine has been operated more frequently and for longer durations for system reliability than was foreseen *when the engineering for its installation was undertaken. Hydro anticipates that there may be emergency situations requiring frequent or long periods of generation from the gas turbine in the future.*

Page 3

The 123.5 MW Holyrood gas turbine, located at the Holyrood Thermal Generating Station site (Holyrood), was installed to provide:

- *Additional long term generation capacity for the Island Interconnected System (IIS);and*
- *Additional generation capacity on the Avalon Peninsula, to mitigate local generation supply and transmission contingencies.*

Page 3

Since being placed in service, the gas turbine has been utilized more frequently and for longer durations than was foreseen during engineering design of the unit. This additional generation is a result of:

- *The requirement to provide generation to obtain appropriate levels of spinning reserve on the IIS due to forecasted system loads and/or forecasted unavailability of other generators, e.g. outages, both planned and unplanned, at the Holyrood Thermal Generating Station;*

- *Facilitation of continuous generation supply in the event of a major generating unit outage or transmission line loss;*
- *Facilitation of planned generation and Avalon Peninsula transmission outages;*
- *Operation as standby generation during circumstances, in which a "single worst Avalon contingency event" could cause sustained customer interruptions; and*
- *The need to provide additional generation to offset hydraulic generation and ensure adequate availability of water-based generation when drier weather conditions and low precipitation periods occur, such as those experienced in late 2015 and early 2016.*

Table 1 provides the forecasted and actual operating hours for the gas turbine from February 2015 to June 2017.

Table 1: Forecasted and Actual Operating Hours – HRD GT from 2015-2017

Year	*Forecasted Running Hours*	*Actual Running Hours*
2015	*184*	*823*
2016	*294*	*1818*
2017	*444*	*237 (to April 30)*

July 28, 2017 Hydro 2018 Capital Budget Application, Turbine Hot Gas Path Level 2 Inspection and Overhaul, Holyrood Gas Turbine

Please refer to NP-NLH-300, Attachment 13 for a copy of Volume II Tab III of Hydro's 2018 Capital Budget Application; Turbine Hot Gas Path Level 2 Inspection and Overhaul, Holyrood Gas Turbine. In its Application, Hydro explains that gas turbine unit manufacturer, Siemens, recommends that a hot gas path inspection and overhaul be completed when the total equivalent starts on the gas turbine reaches 800. At the time, Hydro expected to reach that level in 2019. Specifically, the following excerpts highlight Hydro's operating practices for the unit and provide specific examples.

Page 3

The plant fulfills several key functions in reliably supplying customer demand requirements as follows:

- *The plant is operated to support spinning reserves on the Island Interconnected System. It provides a critical backup in the event of a contingency, such as the loss of a major generating unit.*
- *The plant provides power to the Avalon Peninsula which is heavily reliant on the transfer of power over transmission lines from outside of the Avalon Peninsula, as well as the production of power from the Holyrood Thermal Generating Station. It provides a critical backup in the event of a contingency, such as the loss of a Holyrood unit, or loss of a major transmission line into the area. The plant is also used to facilitate planned generation and Avalon Peninsula transmission outages.*

Page 4

The Holyrood Gas Turbine Plant is important to the reliability of power to the Avalon Peninsula and therefore must be properly maintained.

Monthly Energy Supply Reports

Please refer to NP-NLH-300, Attachment 14 for a summary of instances in which Hydro reported its use of the Holyrood Combustion Turbine in its Bi-weekly and Monthly Energy Supply Reports.

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May 15, 2015

The Board of Commissioners of Public Utilities
Prince Charles Building
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St. John's, NL
A1A 5B2

ATTENTION: Ms. Cheryl Blundon
Director of Corporate Services & Board Secretary

Dear Ms. Blundon:

Re: March 4, 2015 Power Outage Report (*Power Outage/Incident Advisory 2015-H-062*)

Further to your letter of April 21, 2015 regarding the above referenced report, the following are Hydro's responses to the Board's questions.

Q1. In its March 19, 2015 correspondence the Board requested, upon completion of the investigation into the March 4 outage, a copy of the report of the investigation, including the root cause analysis.
a. Did Hydro complete a root cause analysis of the incidents causing the power outage? If so, when will a report be filed with the Board? If not, why not?
b. Is Hydro's investigation into the March 4 outage complete or are there areas of investigation ongoing?
c. Does Hydro intend to file further reports detailing the events leading up to the outage and Hydro's responses to those events?

A1.

a. Hydro did conduct detailed root cause field investigations of the events causing the under voltage situation that were summarized in a report, *March 4, 2015 Power Outage Report- Power Outage/Incident Advisory 2015-H-062* (the "Power Outage Report"), which was filed with the Board on April 10, 2015. Specifically, sections 4.1 and 4.2 of the Power Outage Report identify the two primary causes of the March 4 outage:

4.1 Primary Cause 1
Unit 1 at Holyrood was delayed in returning to service. The hydrogen cooled generator had been degassed to air to make it safe for repair work to proceed. The process of gassing up again for normal operation involves displacing the air with carbon dioxide, then the carbon dioxide with hydrogen. Hydrogen purity has to meet the 90% purity target before the unit can be released for safe and reliable service. In this instance, this process took longer than normally

anticipated. (See Q5 answer for why the process took longer than normally anticipated)

4.2 Primary Cause 2

The Holyrood CT had operated successfully in the days leading up to March 4. There were no failures to start. The failure to start on March 4 was due to the incorrect flow rate of fuel from a fuel valve. When the unit was called to start, the flow rate was too high.

The original design of the fuel valve and its surroundings did not include protection from inadvertent bumping or protection from movement through vibration. It has been determined that no changes to the fuel valve position were made by the construction, commissioning, or operations staff. The possible reasons for the fuel valve coming out of proper adjustment include inadvertent contact with the valve or through a means such as vibration. (See Q6 answer for modifications to this valve.)

The detailed reports containing these analyses (in relation to (i) Holyrood Unit 1 and (ii) the Holyrood combustion turbine ("CT")) are being finalized and will be filed with the Board in May 2015.

Hydro is also undertaking reviews of the contributing factors relating to the March 4 event, from which various changes in practice are being contemplated, as further stated in item (b) below.

b. As noted in Hydro's Power Outage Report, Hydro is completing an ongoing review of the broader impacts of the low voltage condition for additional opportunities to improve the system and customer service, namely:
    1. Hydro's Protection and Control and the Hydro Generation Operations groups are reviewing the resultant trip of the Star Lake generating unit to determine if any changes are warranted to the protection configuration of that unit;
    2. Holyrood Plant engineering personnel are reviewing the resultant protection operation and trip of Holyrood Unit 3 to confirm proper protection; and
    3. Hydro's System Operations personnel are reviewing the protection operation trips of transmission line TL208 and transformer T2 at the Vale (Long Harbour) terminal station to determine whether adjustments are necessary.

c. Hydro will report the conclusions and any additional changes being implemented as a result of the ongoing reviews noted above.

Q2. On the morning of March 4, 2015, despite the Island Interconnected System not being in an N-1 situation, widespread outages resulted from a lack of generation on the Avalon which led to deterioration in system voltage. Given the outcome please provide your comments as to whether or not an N-1 contingency continues to be appropriate for the Island Interconnected System and in particular, for the Avalon Peninsula.

A2. In the days leading up to March 4, the Island Interconnected System was not forecast to be in an N-1 situation from an overall Island generation reserve perspective. This means there would be no sustained customer load interruption for the loss of the single largest unit, barring any transmission limitations. Similarly, the transmission and generation network supplying the Avalon Peninsula was not forecast to be in an N-1 situation for any single contingency for a generation or transmission element as all lines were in service, Holyrood Unit 1 was scheduled to be online prior to the morning peak and the CT was to be available as required. However, as the morning approached two contingencies occurred, the first contingency event was Holyrood Unit 1 not coming online for the peak and the second being the CT failing to start before the peak occurred. With these two contingencies, other small standby generation start-up was initiated. However, as there was insufficient time to have these online, adequate system voltages could not be maintained.

Increasing the system design to an N-2 criterion whereby there would be no customer impact for the two large contingencies such as those experienced would result in increased capital cost for items such as additional generation, transmission lines and voltage control equipment. The benefit to moving to such a criterion would have to be assessed against the future probability of such events and the cost to prevent customer interruptions. Hydro is committed to operate and maintain the assets in a manner to meet the current reliability criterion.

Hydro is therefore of the opinion that an N-1 transmission contingency design criterion continues to be appropriate for the Island Interconnected System and in particular, for the Avalon Peninsula but as indicated above, if equipment performance or condition indicates the probability of service interruptions are too high, least cost mitigating investment should be investigated and proposed. Due to the nature of the recent events and the solutions being implemented, Hydro is not recommending capital investments to meet an N-2 reliability criterion at this time. Hydro regularly reviews operations under an N-1 contingency and is committed to working with Newfoundland Power ("NP") and its other customers to develop strategies which minimize the customer impact, such as the automatic tripping of feeders under low voltage conditions, for rare multiple contingency events.

Q3. ***If the N-1 contingency remains appropriate, what protections has Hydro put in place to ensure similar events and outages will not occur?***

A3. Hydro has placed several protections in place to ensure similar events do not occur.

- As indicated in the March 4 Power Outage Report, Hydro has taken corrective action addressing the starting problem with the new CT. (see Q6 answer)
- Hydro has also expanded its daily reviews and reporting of reserves to include a dedicated assessment of system conditions on the Avalon Peninsula.
- System security assessments of both the Island Interconnected System and the Avalon Peninsula are now performed daily based on current load forecasts for the next seven days. The assessments allow for advance coordination of primary generation, standby

generation, and sources of reactive support, such as capacitor banks. These assessments are used in concert with the customer and stakeholder communications protocols described in the report.

- As discussed on page 10 of the March 4 Power Outage Report, under voltage protection settings for the CBC banks have been changed to help ensure that capacitor banks do not trip for transient disturbances or during steady-state operation outside of acceptable voltage limits, as per the events of March 4. This will have the effect of reducing the impact on customers.
- The Power Outage Report also discusses an investigation of the application of an under voltage load shedding scheme. This analysis, performed in cooperation with NP, will involve the specification of a protection system that will trip feeders when voltages drop below prescribed thresholds. Such an automated scheme would help to ensure that the system operates within specified voltage limits that will prevent the consequential tripping of generators that caused a larger customer impact in terms of the number and duration of customer interruptions.

Q4. ***At page 2, line 20 Hydro indicates it performed an Avalon Load Flow Analysis in support of the N-1 Contingency. Provide a comparison of how the actual events of March 4, 2015 deviated from the modeled events of the Avalon Load Flow Analysis.***

A4. System load flow studies were completed on February 27 that modelled Unit 1 out of service and the Holyrood CT and Hardwoods gas turbine fully available. The purpose of the load flows was to determine whether there was a requirement to change the system load levels at which standby units should be dispatched, because of Avalon transmission constraints, to cover an N-1 contingency.

An additional load flow was performed on March 2. As per the response to Question 13, this analysis indicated that a total Gross Avalon[1] Load of 755 MW could be supported with Unit 1 at Holyrood, the Hardwoods Gas Turbine and the Holyrood Combustion Turbine all off line. Of the two load flows performed in advance of March 4, the most representative load flow analysis of the March 4 events is discussed below.

The actual events of March 4 deviated from the modeled events primarily due to the following:

- Hardwoods Gas Turbine was available at 25 MW as opposed to unavailable; and
- The power factor of load on the Avalon Peninsula was approximately 0.99 as opposed to 0.975.

As discussed in the report, system voltages were within acceptable ranges until approximately 07:09. At this time, Gross Avalon Loads reached a peak value of approximately 827 MW. At this threshold, system voltages declined as reactive power limits were reached. It may therefore be

[1] The Gross Load is the sum of all the generators operating on the Avalon and the load transferred from TL203 and TL237 at Western Avalon.

concluded that the increased power factor and the availability of the Hardwoods Gas Turbine as a synchronous condenser allowed for the support of additional Gross Avalon Load above 755 MW.

In summary, the events of March 4 deviated from previous analysis in that additional load on the Avalon Peninsula above 755 MW was supported as a result of (1) a higher actual power factor that was experienced compared to that which was modelled and (2) the availability of the 25 MW at the Hardwoods Gas Turbine.

As loads increased, there was insufficient reactive and real power on the Avalon Peninsula and for the system voltages to stay within operational limits. While operating outside of specified voltage limits, an additional contingency occurred involving the trip of the CBC capacitor banks.

Q5. ***At Section 4.1, Primary Cause 1, the primary cause of the outage is identified as being the delayed return to service of Unit 1 due to a longer than normally anticipated gassing up of the unit.***
a. How long does the gassing up process normally take?
b. When did gassing up of Unit 1 commence?
c. When was the process completed?
d. Why did the process take longer than normally anticipated?

A5.

a. The full gassing up process normally takes approximately 16-24 hours.

b. Gassing up of Unit 1 commenced at 9:00 p.m. on March 2.

c. The gassing up of Unit 1 was completed at 4:30 a.m. on March 4[2].

d. The gassing up process on Unit 1 extended beyond the normal range of time. The process involves purging the air with carbon dioxide, and then replacing the carbon dioxide with hydrogen gas. The injection of the carbon dioxide took longer than expected due to lower than typical carbon dioxide flow rates. The lower flow rates were subsequently discovered to be caused by a leak, which was repaired.

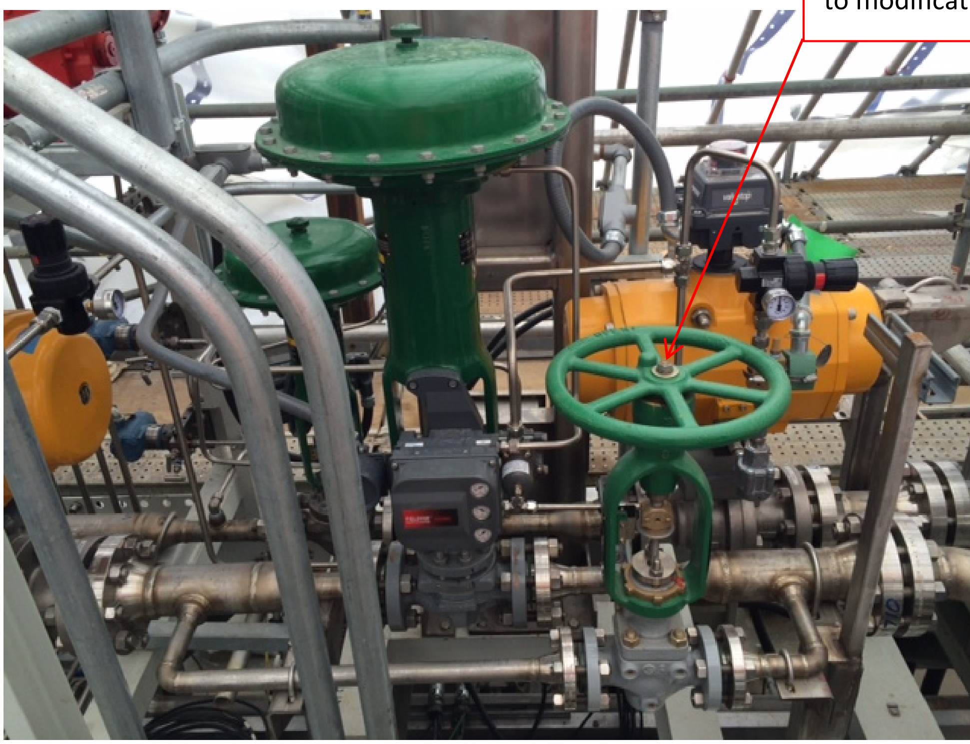
Q6. ***At Section 4.2, Primary Cause 2, a further cause of the outage is identified as being the incorrect flow rate of fuel from a fuel valve on the Holyrood Combustion Turbine.***
a. Provide pictures of the valve in question prior to any lock out modifications effected.
b. Provide pictures of the valve in question following lock out modifications effected.
c. Provide a clear indication either through photographs or diagrams as to the location of the valve on the unit and its accessibility for inadvertent contact.

[2] Following successful gassing up of the unit, there are several remaining activities to complete before the unit is online and generating. These activities typically take 8-12 hours.

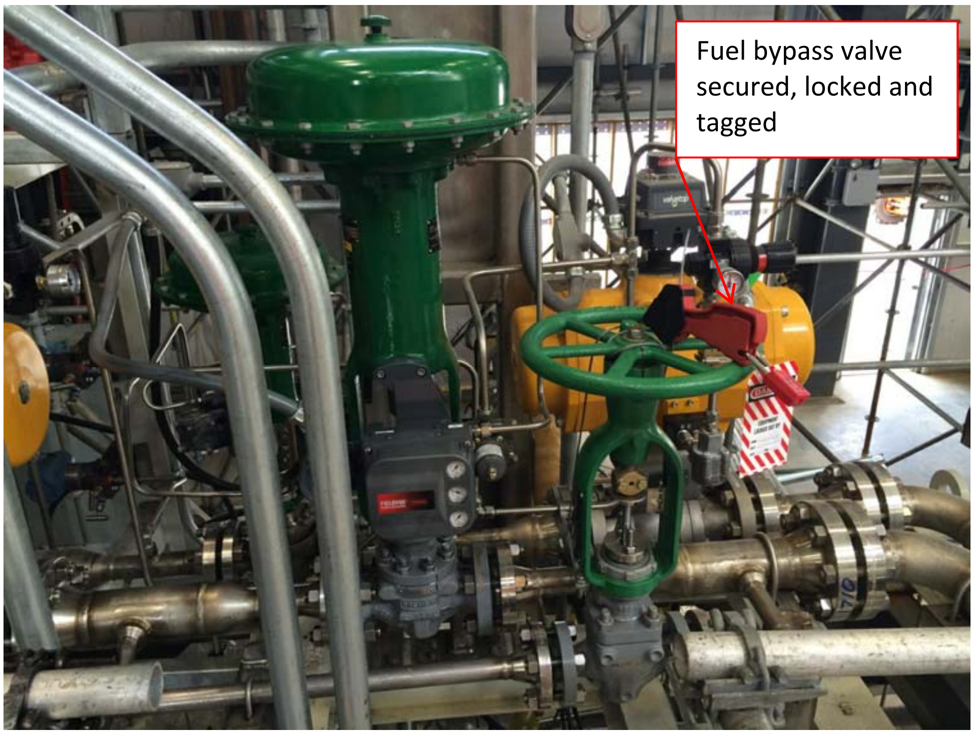
A6.

a. Please see the photo below showing the fuel valve prior to any lock out modifications being affected.

Fuel valve prior to modification



b. Please see the photo below showing the valve following lock out modification. The valve has been secured, locked and tagged. While it is not visible in the photograph, the valve has also been marked to indicate the valve set position and a pre-start up verification of the valve position has been instituted.



c. Please see the photos below showing the location of the valve. The valve is not located on the turbine itself, it is located on the fuel, oil, and water injection skid, on an elevated platform within the plant. As can be seen in the photos, scaffolding is in place to facilitate access to the area.

Q7. ***At 00:28 Hydro's Energy Control Centre (ECC) knew that Unit 1 return to service would be delayed. At 05:24 the EEC knew Unit 1 would not be available to meet morning peak demand. At 06:30 Hydro knew the Holyrood Combustion Turbine was not available and likely would not be available to meet morning peak demand. At 07:01 Hydro advised Newfoundland Power of system generation issues and that Holyrood Unit 1 and the Combustion Turbine were unavailable. Why was notification of the system generation issues not provided to Newfoundland Power earlier than 7:01?***

A7. In referencing the joint timeline filed with the Board on March 27, by NP and Hydro, notification was given by the Energy Control Centre ("ECC") to the NP System Control Centre ("SCC") at 06:51 regarding the situation that the CT would not start and that the 230 kV system voltage was down to 216 kV. Shared SCADA information available also indicated to NP the real-time status of the Holyrood units. Notification prior to this time was not given as the system operator was anticipating the start-up of the CT at any moment to avoid manual load shedding of customers.

Q8. ***At page 11 it is indicated that in the future inter-group communication between Holyrood Operations and Hydro's ECC will include the most likely return to service time as a well as a range of return to service time where such risk exists. What changes to inter-utility communications will Hydro implement to provide immediate notification to Newfoundland***

Power of delays in returning significant assets to service from the original scheduled return to service time and to provide regular updates to Newfoundland Power as to the status of the return to service of those assets such as hourly or every two hours if return is imminent?

A8. Since the March 4 power outage, Hydro has updated its capability assessment and notification protocols (including an operating instruction; currently in draft and pending approval) to include the communication of the Avalon capability and reserve to NP, similar to what is currently in place for the assessment and notification of Island capability and reserve. If the availability of assets on the Avalon changes, Hydro will perform reliability assessments in order to determine the Avalon capability and reserve for each of the upcoming seven days. If the reserve in any day is less than the impact on the Avalon capability of the largest contingency, plus a buffer of 35 MW, Hydro will communicate with NP at regular intervals until the Avalon reserve returns to normal levels, above the threshold that requires further notification.

Examples of this occurred on the weekend of April 18 to 19. On April 18, at 00:12, Holyrood Unit 2 came off line for a fuel leak. As a result, the Holyrood CT was requested to start at 01:02 but it failed to start as requested. With two assets on the Avalon potentially unavailable for the morning peak and the Avalon reserve forecast to be at levels that required notification (if the two units remained unavailable), NP was advised at around 03:00. At 03:33, the Holyrood CT became available for service and the forecast Avalon reserves returned to acceptable levels and another call was made to NP to advise them of the same. A similar event occurred the following day when Hydro issued a Power Watch[3] when there was a potential of having to take Holyrood Unit 2 off line for a steam leak. Later in the day, Hydro rescinded the Power Watch, as the unit did not need to be removed from service. Through this event, NP was kept abreast of the forecast reserve on the Avalon and the status of Holyrood Unit 2.

In addition to the aforementioned, the daily status updates[4] provided to NP now include the Avalon capability and reserve forecast.

Q9. ***At page 12, line 23 it is stated "The response of system operator personnel to declining voltages...has been improved"***
a. Provide details of the improvements in system operator response i.e. changes made, training provided, lessons learned.
b. What specific procedures will Hydro implement to give direction to system operators as to how to respond to a similar voltage deterioration event?

---

[3] Power Watch means the reserve on the Avalon was less than the impact to the Avalon capability of the single worst contingency event.
[4] The daily status updates originally included the status of major equipment, planned equipment outages and the Island capability and reserve forecast.

A9.

a. Hydro System Operations performed a lessons learned exercise shortly after the March 4 power outage and from this, a number of improvements were made to bring greater awareness to the system operators about the Avalon power system and its capabilities and vulnerabilities. The improvements are noted as follows:
   - The trip setting on the four CBC capacitor banks were reviewed and modified. This will help the system operators, by adding more time to deal with a potential voltage decline event;
   - The operating instructions relating to equipment ratings and bus limits were reviewed with system operators. The need for prompt and coordinated manual load shedding (with NP) was emphasized, to ensure acceptable delivery point bus voltages as system voltages decline to established limits;
   - Although the following would not have had any impact on March 4, as the units were already dispatched for Island reserve purposes, Hydro has since reviewed its transmission reliability criteria and has commenced the practice of operating standby generating units (that support the Avalon) in advance of Avalon transmission system contingencies, rather than starting them after the event has occurred. To support this improvement, beginning in late March 2015, system operators have been receiving standby generation requirements for supporting the Avalon transmission;
   - Beginning on April 8, 2015, a daily report has been prepared within System Operations that forecasts the Avalon capability, the impact on the capability of the system in the event of the largest single contingency and the Avalon reserve for the upcoming seven days. This report is used by the system operators to understand the Avalon capability with specified assets available and under the single worst contingency;
   - An Operator Training Simulator session is being planned that simulates the events of March 4. This session will allow all of the system operators to experience declining voltages on the Avalon power system and learn how best to respond; and
   - Hydro and NP are working on an automatic under voltage load shedding scheme for the Avalon power system that will essentially remove the need for system operators to perform manual load shedding in the face of declining voltages. This scheme will be similar to the existing under-frequency load shedding scheme, triggered typically by the loss of generation above the 50 MW level.

b. As stated in Question 8, Hydro System Operations has developed a new operating instruction (currently in draft and pending approval) to help the system operators better assess the Avalon power system capability and reserve, and to maintain greater online generation reserves on the Avalon. This instruction, together with existing instructions on equipment ratings and bus limits, will help the system operators deal with an event similar to the one experienced on March 4.

Q10. ***During the outage Hydro's website advised that no power outages were being experienced by Hydro customers. While technically accurate Hydro omitted to notify the public of a significant loss of supply to the system. What actions has Hydro taken to provide public notification on its***

website in the event of future significant loss of supply affecting other than Hydro Domestic and General Service Customers?

A10. There is currently a manual process in place for the Hydro web site to place a red alert banner on the main page advising of a system event. On the morning of March 4, this was done at 07:52. The red banner included a link to information on the Advance Notification Levels and effective ways to conserve electricity. Although the banner was at the top of the page in bright red, feedback was received that customers were not able to see the banner. As a result, Hydro has moved the banner to the centre of the main web page, right above the main navigation icons (see Appendix 1).

An additional communication feature has been added to the website, which allows a pop-up display to take over the main page of the website, advising customers of a power alert. Customers must close this pop-up before they can access the rest of the site, including the customer outages page. This is an added feature to ensure anyone visiting Hydro's website is made aware of a power alert in effect (see Appendix 2).

The "Outages" button on the front page of the Hydro's website links to the distribution customer Power Outage and Emergency System. This is a system developed for Hydro's own distribution customers. It is programmed by telephone exchange and area and is specifically coded to contain only Hydro's rural distribution systems. The system is near end of life and Hydro are currently reviewing options to replace this system this year. Hydro will assess whether potential systems have the ability to communicate broader system equipment outages and advisories, which may not directly affect its distribution customers.

Q11. ***Provide a graph(s) showing the relationship between the generation on the Avalon, the load on the Avalon, the load on the in-feed from Bay d'Espoir and the voltages on the Avalon.***

A11. The relationship between the generation, the load, the in-feed from Bay d'Espoir, and voltages on the Avalon Peninsula are demonstrated in the figures provided below. These figures were developed based on load flow analysis performed using Version 32 of PSS®E software from Siemens PTI.

Figure 1 includes illustrations of voltages[5] and reactive support on the Avalon Peninsula versus Gross Avalon Demand. Gross Avalon Demand is calculated as the sum of the following sources of supply:

- Thermal generation from Holyrood units;
- Generation from the CT;
- Generation from the Hardwoods Gas Turbine;
- Hydraulic generation from NP units;

[5] Voltages at the 230 kV bus at Oxen Pond Terminal Station are provided as representative system voltages for the purposes of this demonstration.

- Diesel generation at Vale Terminal Station; and
- Sum of power delivered from 230 kV transmission lines TL203 and TL237 at the Western Avalon Terminal Station.

As indicated, voltages are held above the minimum thresholds over the operating range. This is accomplished by increasing reactive support on the Avalon Peninsula through the operation of capacitor banks and by bringing additional generators online, as illustrated by the red line in the plot below.

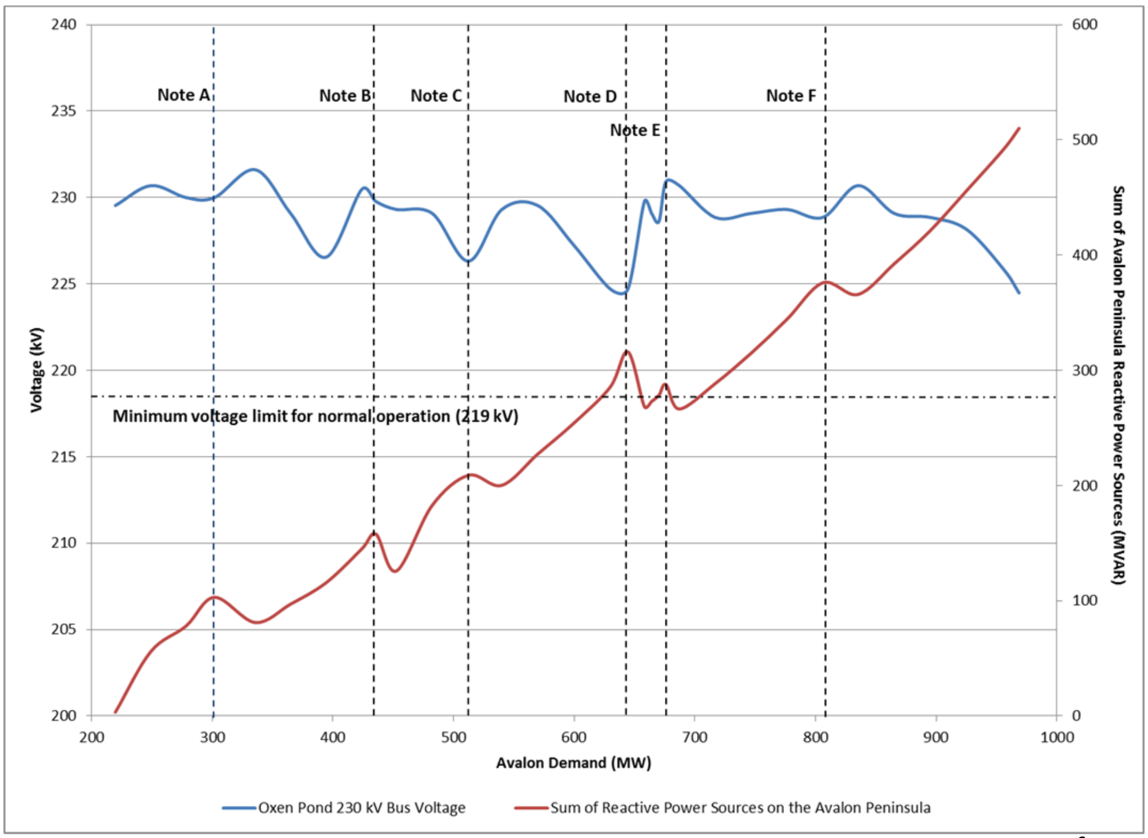


Figure 1 – Avalon Peninsula Voltages and Reactive Power vs Gross Avalon Demand[6]

[6] Note A: Below 305 MW, Avalon demand is met using hydraulic generation. Standby units (the CT and Hardwoods Gas Turbine) brought online as Gross Avalon Demand exceeds 305 MW.
Note B: One Holyrood unit online as Gross Avalon Demand exceeds 435 MW.
Note C: One Holyrood unit and standby units online as Gross Avalon Demand exceeds 515 MW.
Note D: Two Holyrood units online as Gross Avalon Demand exceed 645 MW.
Note E: Two Holyrood units and standby units online as Gross Avalon Demand exceed 675 MW.
Note F: Three Holyrood units and standby units online as Gross Avalon Demand exceed 810 MW.

Figure 2 includes illustrations of the sources of supply on the Avalon Peninsula versus Gross Avalon Demand associated with Figure 1. "Avalon Generation" includes the following sources of supply:

- Thermal generation from Holyrood units;
- Generation from the CT;
- Generation from the Hardwoods Gas Turbine;
- Hydraulic generation from NP; and
- Diesel generation at Vale Terminal Station.

Power flows from Bay d'Espoir over transmission lines TL202 and TL206 are also provided, as requested.

Exact system dispatches may vary based on operating conditions. For demonstration purposes, the load flow analysis was performed assuming that units are brought online at rated capacity.

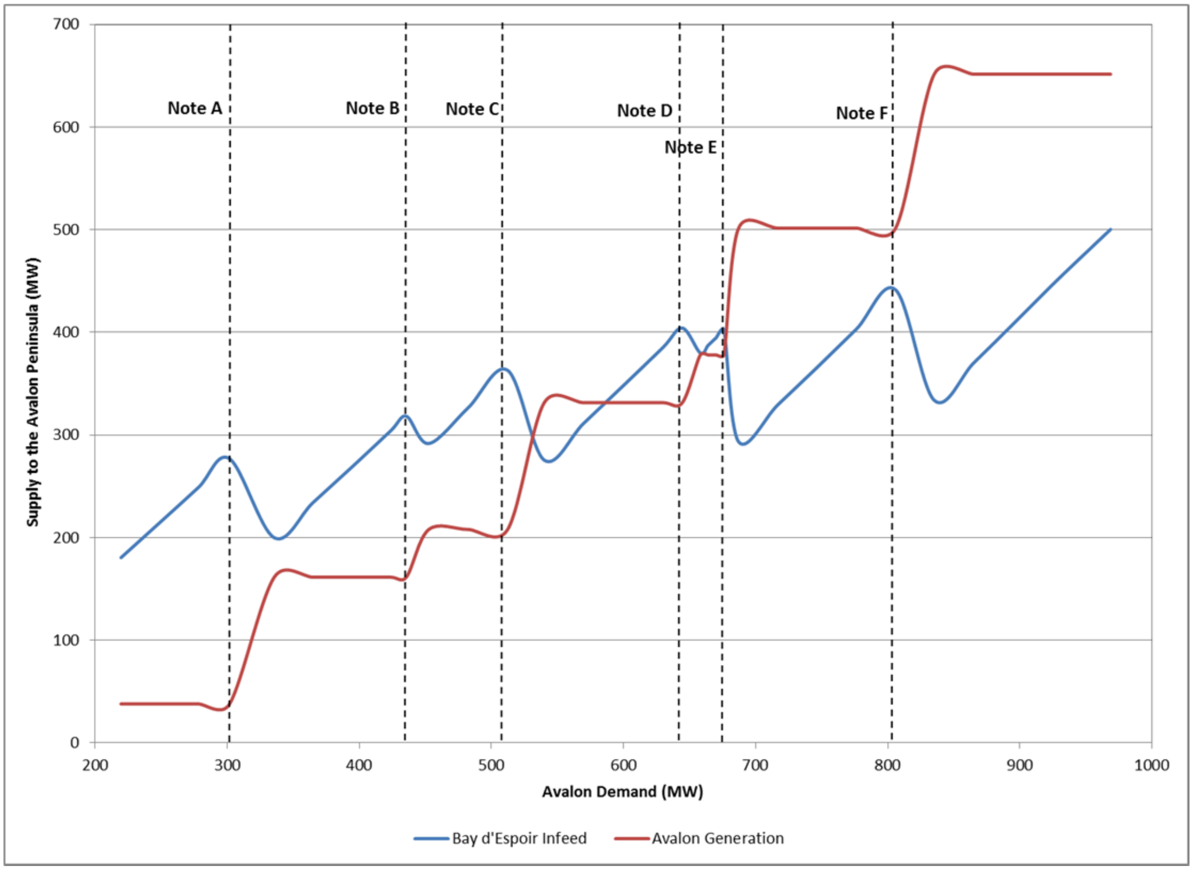


Figure 2 – Sources of Supply for the Avalon Peninsula[7]

Q12. ***Provide a description of the tools (e.g. load flow studies) available to system operators to determine system voltages as a result of generation or transmission outages. Include in the response the time required to carry out these studies and if they could have be carried out in the time between 06:12 and 07:04 on March 4, 2015.***

A12. Prior to approving equipment outages, Hydro System Operations engineers may perform, or ask the System Planning engineers to perform, load flow studies to determine the systems capability with the equipment outage and further unforeseen equipment outages during the planned

[7] Note A: Below 305 MW, Avalon demand is met using hydraulic generation. Standby units (the CT and Hardwoods Gas Turbine) brought online as Gross Avalon Demand exceed 305 MW.
Note B: One Holyrood unit online as Gross Avalon Demand exceeds 435 MW.
Note C: One Holyrood unit and standby units online as Gross Avalon Demand exceeds 515 MW.
Note D: Two Holyrood units online as Gross Avalon Demand exceed 645 MW.
Note E: Two Holyrood units and standby units online as Gross Avalon Demand exceed 675 MW.
Note F: Three Holyrood units and standby units online as Gross Avalon Demand exceed 810 MW.

equipment outage.[8] Once the outage has been approved and during day-to-day system operations, the system operators use an Energy Management System ("EMS") to monitor and control the power grid.

There are a number of operational tools as a part of the EMS, such as load flow studies that the system operators use to support the safe and reliable operation of the transmission system. One such application on the EMS is Network Analysis. This application provides system operators with the ability to perform studies of the power system using real time data. Network Analysis contains a model of the power system and its associated equipment, including generators, transmission lines, transformers and busses. It also includes the majority of NP's equipment. Using the features of the application, system operators can take a snapshot of the current power system using the most recent power flow data. Once the current real time data has been captured into the power system model, the system operator can simulate changes on the power system, including equipment outages and load variations, to determine impacts resulting from those changes. From power system simulations, the system operators are able to determine the impact of changes on the transmission voltages. The time required to perform a typical power system study is generally between 30 and 45 minutes, depending on the complexity of the simulation.

Another application on the EMS is Contingency Analysis ("CA"). This application indicates to the system operators the single worst-case contingency on the power system at the time the application runs. It does not work with forecast loads. CA has a number of equipment outages defined and will run a load flow for each contingency. The application then ranks each contingency in the order of severity and the results are displayed to the system operators. The severity is rated both from a voltage and thermal overload perspective. CA runs on the EMS automatically and is updated every five minutes. On the morning of March 4, the CA application would not have provided any new information to the system operators as the contingencies of Holyrood Unit 1 and the CT not being available were already reflected in the real time power system model and all mitigating actions short of directing the shedding of feeders to reduce load had been implemented.

Q13. ***Were there system studies completed at any time prior to March 4, 2015 that simulated the conditions of or similar conditions of March 4, 2015?***

A13. System load flow studies were completed on February 27 that modelled Unit 1 out of service and the Holyrood CT and Hardwoods gas turbine fully available. The purpose of the load flows was to determine whether there was a requirement to change the system load levels at which standby units should be dispatched because of Avalon transmission constraints to cover an N-1 contingency.

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[8] These are the studies referenced in the response to Question 4 and in the Power Outage Report.

An additional load flow was performed on March 2. This analysis was updated as one end at Hardwoods became unavailable the previous day. In response to this request, an analysis was performed to assess the impacts of additional Avalon contingencies. These contingencies included the loss of an additional generating unit at Holyrood, the loss of transmission line TL202, or the loss of the CT.

The analysis for the scenario involving outages to Unit 1 at Holyrood, the Hardwoods Gas Turbine, and the CT is summarized as follows:

- Holyrood Unit 1: out of service;
- Holyrood Unit 2: available for 170 MW;
- Holyrood Unit 3: available for 150 MW;
- CT: out of service;
- Hardwoods Gas Turbine: out of service;
- NP Generation on the Avalon Peninsula available in accordance with firm supply of 38 MW;
- No generation from wind farms;
- All capacitor banks available;
- No generation from Holyrood mobile diesels, Vale, Greenhill, or Wesleyville units; and
- Load power factor of 0.975 on the Avalon Peninsula.

The results of this analysis indicated that the Holyrood CT should be dispatched prior to the Avalon load reaching 755 MW with Holyrood unit 1 off line. Consistent with this, the Holyrood CT was scheduled to be online by 06:00 on March 4.

Q14. ***Provide load flow study results for March 4, 2015 in diagrammatic form in 15 minute intervals commencing at 06:15 until 07:14 for the Island Interconnected System.***

A14. Please see Appendix 3 for load flow plots for the interval commencing at 06:15 until 07:14 for the Island Interconnected System. The plots illustrate system bus voltages, real power flows (provided above the line) and reactive power flows (provided below the line) on the Avalon Peninsula.

System elements are coloured to represent operating voltages as per Hydro convention:

- 230 kV elements: Red
- 138 kV elements: Green
- 66/69 kV elements: Blue
- Low voltage elements: Brown

If the voltage of a bus drops below 95% of nominal value, the colour is changed to grey. For example, the Oxen Pond 66 kV bus is coloured blue at 07:00 and grey at 07:14. As per the events described in the Power Outage Report, the plots contained in the appendix detail the system conditions over the specified timeframe. As indicated, system voltages are acceptable prior to 07:00. At 07:00, low voltage conditions are noted at 230 kV buses at Western Avalon Terminal Station, Voisey's Bay Nickel (Vale Inco) Terminal Station, Hardwoods Terminal Station, and Oxen Pond Terminal Station. Extensive low voltage conditions are noted at 07:14.

It should be noted that the load flow plots are simulated results that may have minor deviations from measured values on the day of the system events.

Q15. ***Provide a description of training provided to system operators regarding voltage requirements on the Avalon Peninsula for various generation and load configurations.***

A15. A component of the EMS is the Operator Training Simulator ("OTS"). This is used to train the system operators in both normal and emergency operation of the power system. Scenarios are developed which simulate various generation and load configurations. System operators can operate on the OTS as it simulates real time operation. They can see the impact of contingencies, learn how to respond and complete restorations.

OTS training is scheduled three times each year. There are many different scenarios that have been developed but the several current scenarios relevant to the Avalon Peninsula and voltage requirements are:

- East coast restoration with the loss of TL202 and TL206;
- East coast restoration with the loss of TL201 and TL217;
- Trip of a Holyrood unit which would cause under-frequency load shedding;
- Restoration of Hardwoods and Oxen Pond terminal stations; and
- Black start of the Holyrood Plant from the Hardwoods Gas Turbine.

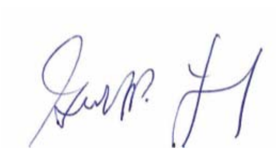
Each of these scenarios has components of voltage requirements and monitoring. As the system operators go through the simulation of restoration, they learn how load restoration impacts system voltages. The system operators must maintain these voltages within acceptable levels. As well, there are system operating instructions that are relevant to these scenarios and they would be used as part of the training. These instructions are procedures for restoration and maintaining acceptable operating criteria. In essence, the OTS training would also keep the system operators up to date on these operating instructions.

System operators have also been given training in alarm monitoring and management. This was completed as part of an OTS training session and was developed to ensure the system operators understand what is required if there is an alarm at a terminal station. Essentially, it is an understanding of what needs to be completed before restoration can commence.

If you have any questions or comments, please contact the undersigned.

Yours truly,

NEWFOUNDLAND AND LABRADOR HYDRO



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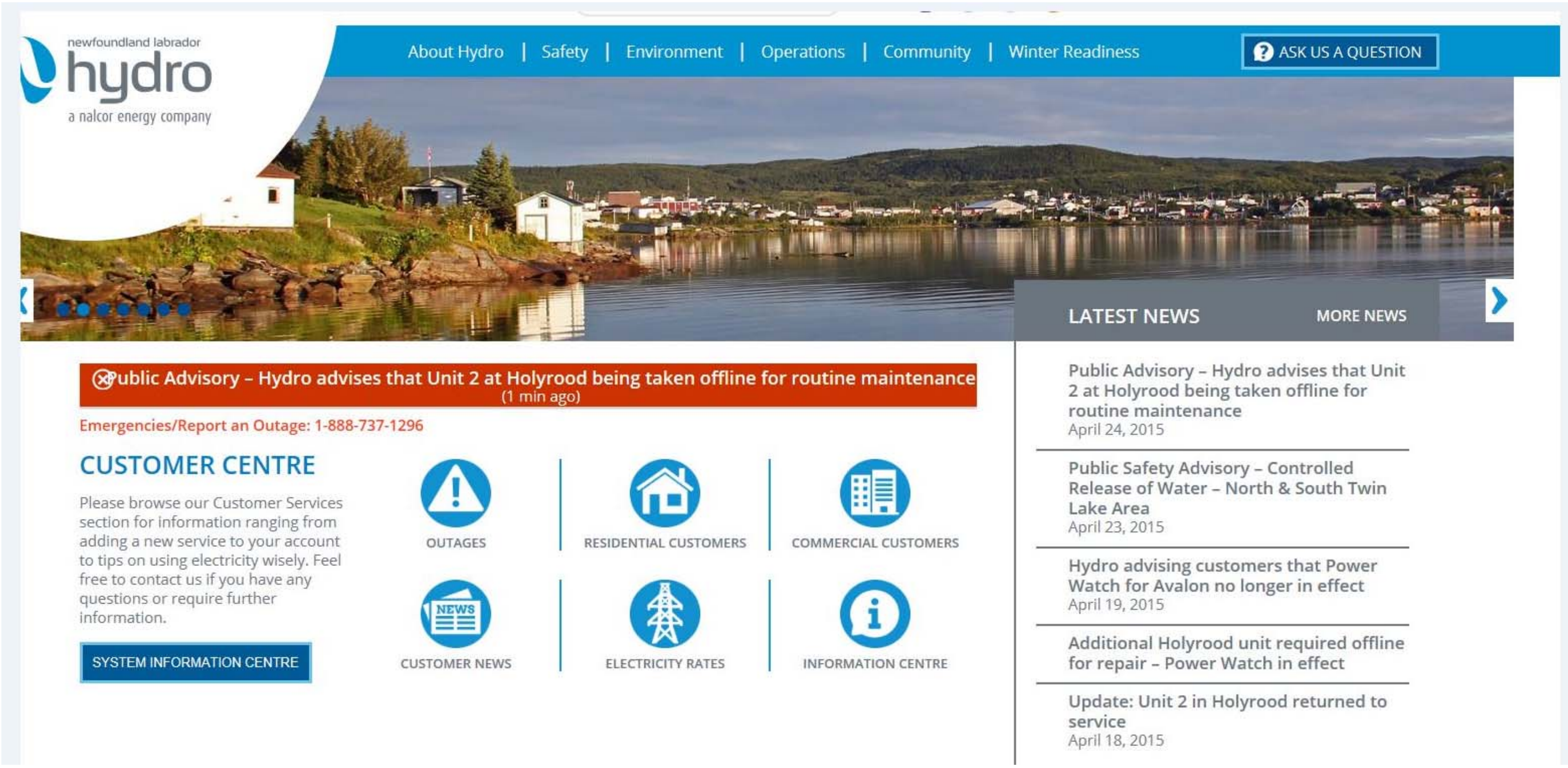
Geoff P. Young
Senior Legal Counsel

GPY/jc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a nalcor energy company
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Public Advisory – Hydro advises that Unit 2 at Holyrood being taken offline for routine maintenance
(1 min ago)
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Please browse our Customer Services section for information ranging from adding a new service to your account to tips on using electricity wisely. Feel free to contact us if you have any questions or require further information.
SYSTEM INFORMATION CENTRE
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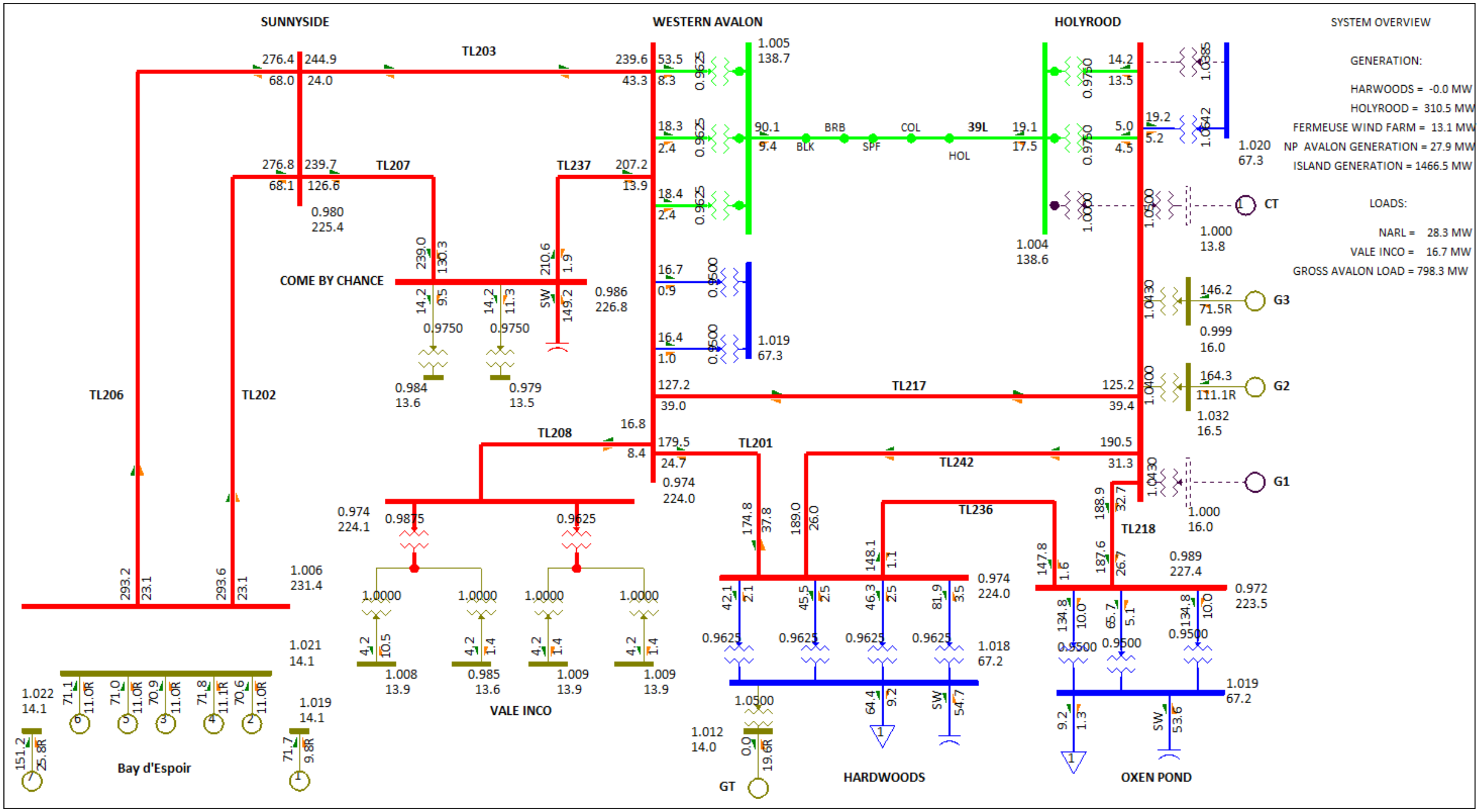
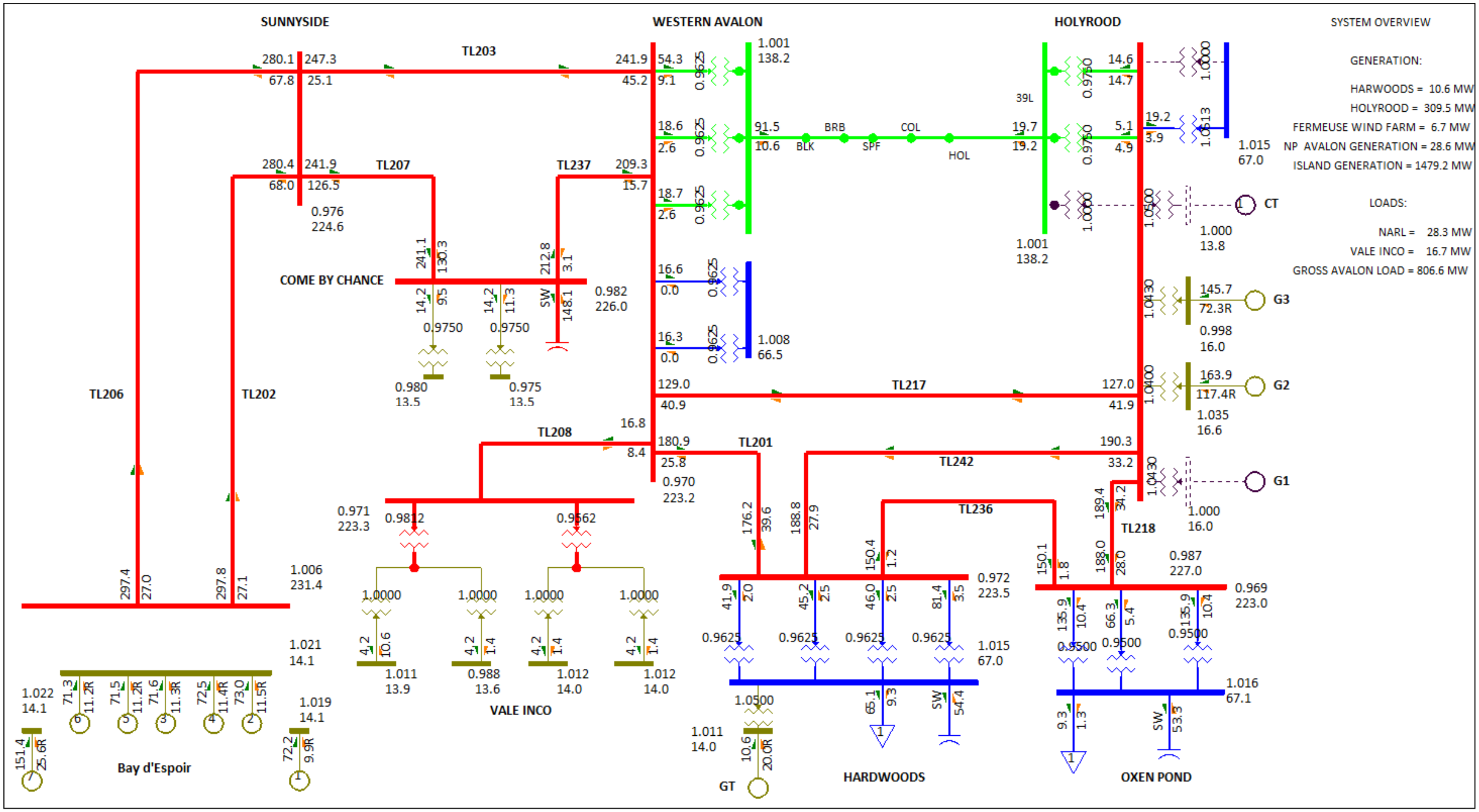
RESIDENTIAL CUSTOMERS
COMMERCIAL CUSTOMERS
NEWS
CUSTOMER NEWS
ELECTRICITY RATES
INFORMATION CENTRE
Public Advisory – Hydro advises that Unit 2 at Holyrood being taken offline for routine maintenance
April 24, 2015
Public Safety Advisory – Controlled Release of Water – North & South Twin Lake Area
April 23, 2015
Hydro advising customers that Power Watch for Avalon no longer in effect
April 19, 2015
Additional Holyrood unit required offline for repair – Power Watch in effect
Update: Unit 2 in Holyrood returned to service
April 18, 2015


ATTENTION RESIDENTS OF NEWFOUNDLAND & LABRADOR, WE ARE NOW IN A
POWER WARNING
Our electricity supply is getting close to maximum demand. We need you to:
1. Conserve energy.
2. Be prepared for possible power outages.

Appendix 3, Page 1 of 5



06:15:00 AM


SUNNYSIDE
WESTERN AVALON
HOLYROOD
SYSTEM OVERVIEW
GENERATION:
HARWOODS = 10.6 MW
HOLYROOD = 309.5 MW
FERMEUSE WIND FARM = 6.7 MW
NP AVALON GENERATION = 28.6 MW
ISLAND GENERATION = 1479.2 MW
LOADS:
NARL = 28.3 MW
VALE INCO = 16.7 MW
GROSS AVALON LOAD = 806.6 MW
TL203
TL207
TL237
TL206
TL202
TL217
TL208
TL201
TL242
TL236
TL218
COME BY CHANCE
VALE INCO
Bay d'Espoir
GT
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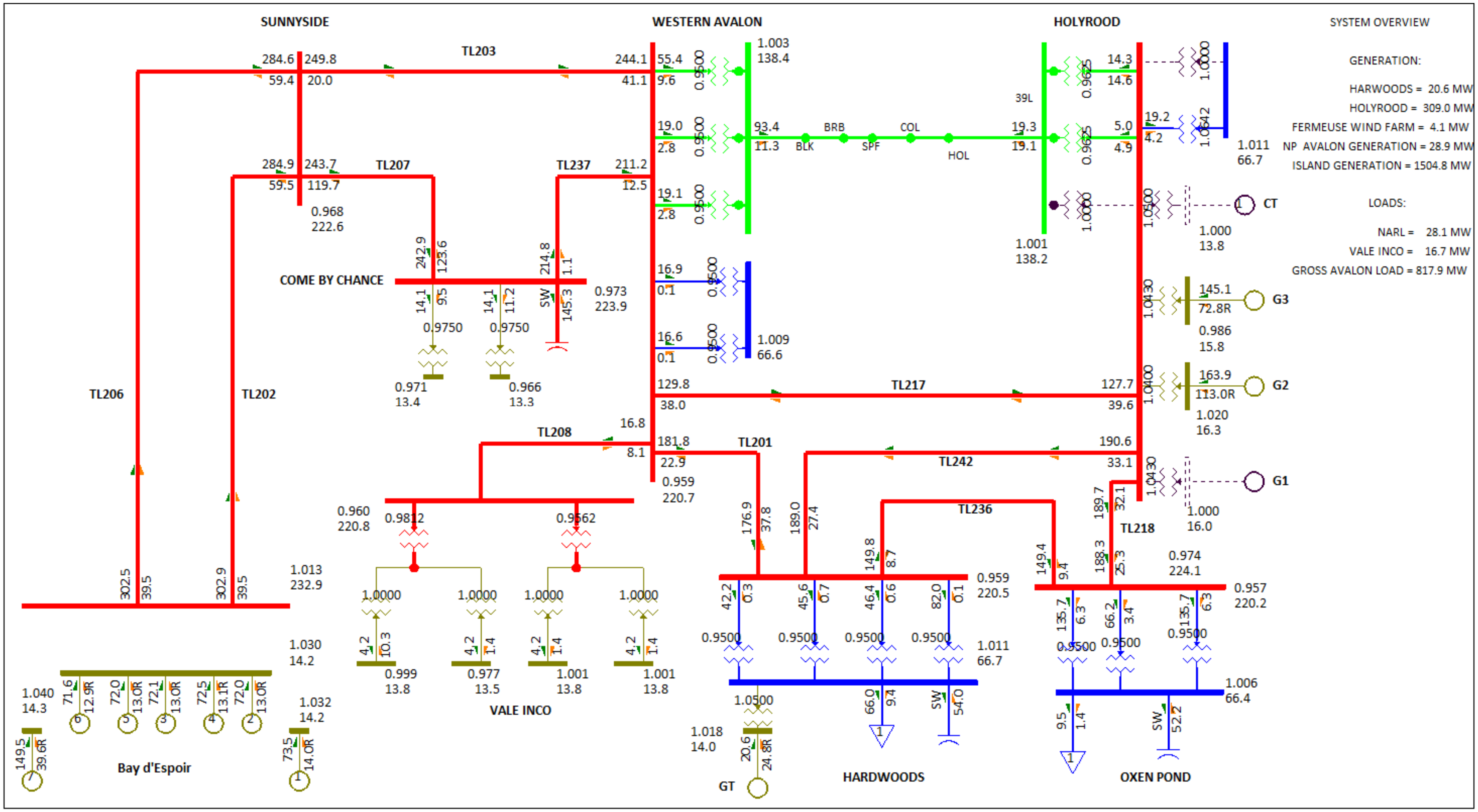
06:30:00 AM


SUNNYSIDE
WESTERN AVALON
HOLYROOD
SYSTEM OVERVIEW
GENERATION:
HARWOODS = 20.6 MW
HOLYROOD = 309.0 MW
FERMEUSE WIND FARM = 4.1 MW
NP AVALON GENERATION = 28.9 MW
ISLAND GENERATION = 1504.8 MW
LOADS:
NARL = 28.1 MW
VALE INCO = 16.7 MW
GROSS AVALON LOAD = 817.9 MW
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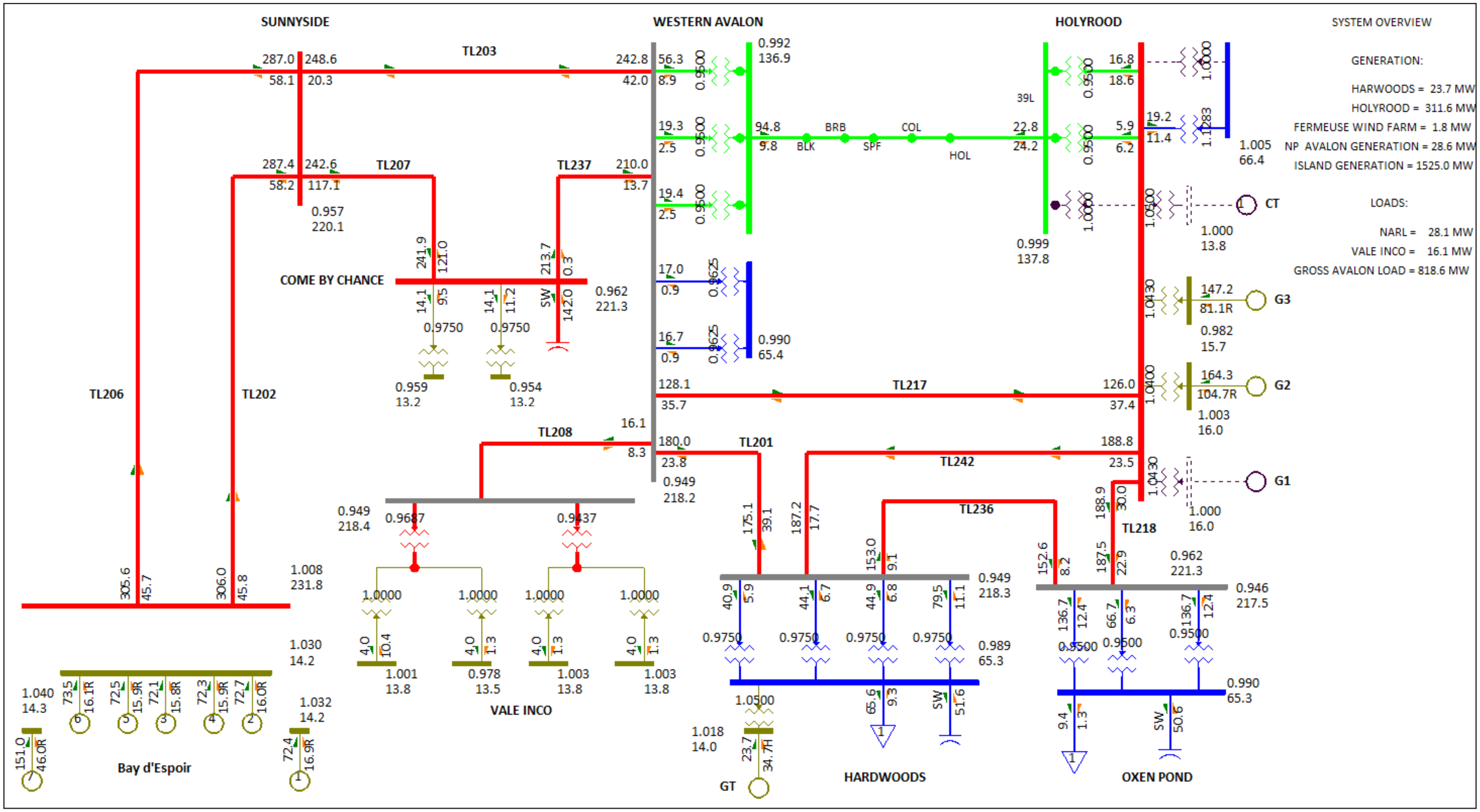
VALE INCO
HARDWOODS
OXEN POND

06:45:00 AM


SUNNYSIDE
WESTERN AVALON
HOLYROOD
SYSTEM OVERVIEW
GENERATION:
HARWOODS = 23.7 MW
HOLYROOD = 311.6 MW
FERMEUSE WIND FARM = 1.8 MW
NP AVALON GENERATION = 28.6 MW
ISLAND GENERATION = 1525.0 MW
LOADS:
NARL = 28.1 MW
VALE INCO = 16.1 MW
GROSS AVALON LOAD = 818.6 MW
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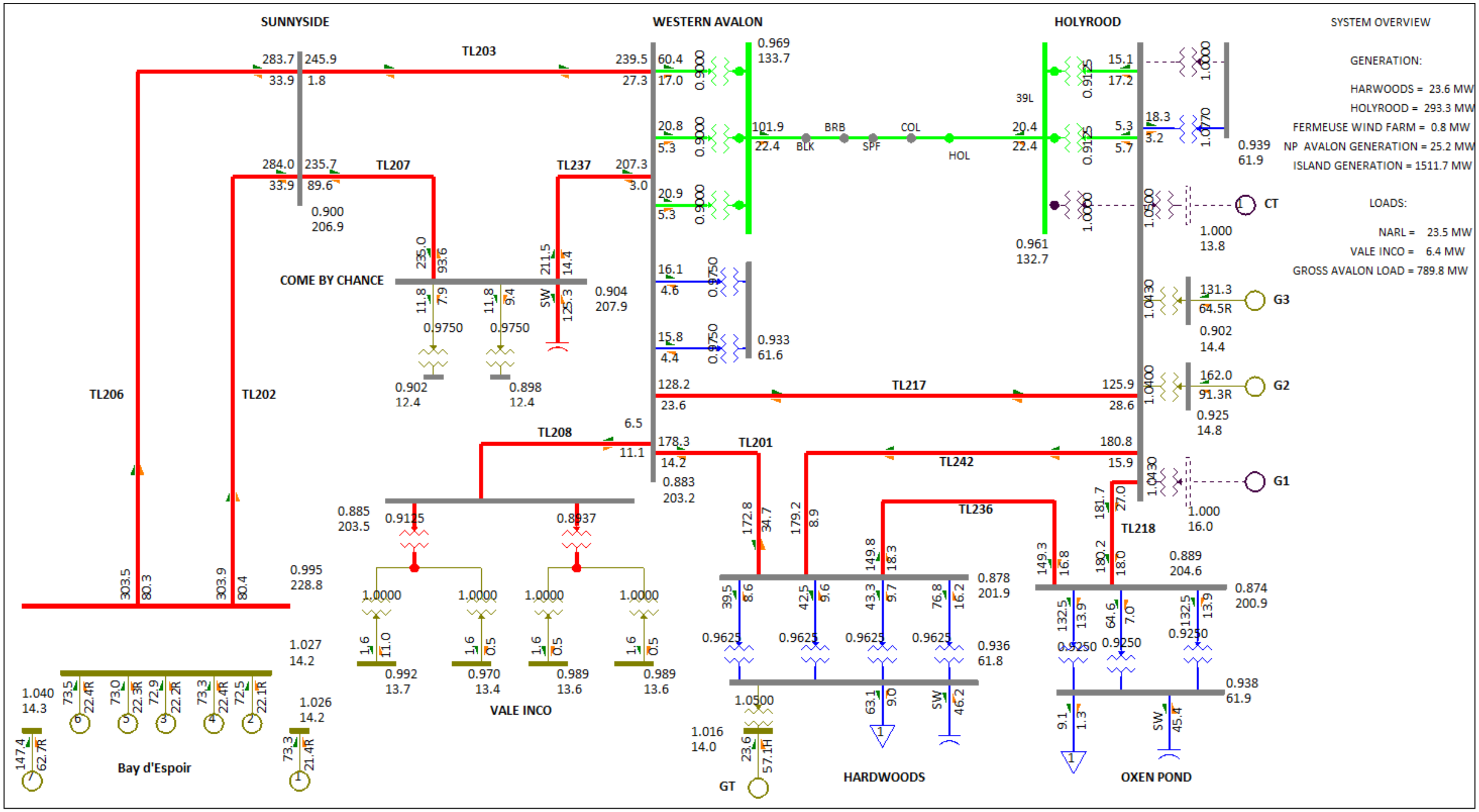
07:00:00 AM


SUNNYSIDE
WESTERN AVALON
HOLYROOD
SYSTEM OVERVIEW
GENERATION:
HARWOODS = 23.6 MW
HOLYROOD = 293.3 MW
FERMEUSE WIND FARM = 0.8 MW
NP AVALON GENERATION = 25.2 MW
ISLAND GENERATION = 1511.7 MW
LOADS:
NARL = 23.5 MW
VALE INCO = 6.4 MW
GROSS AVALON LOAD = 789.8 MW
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COME BY CHANCE
VALE INCO
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Bay d'Espoir
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G2
G3
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SPF
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39L

07:14:00 AM

Page 129

MS. GLYNN:
Q. Is the undertaking accepted?
MR. YOUNG:
Q. He's writing it down.
MR. O'BRIEN:
Q. I think your lawyer is looking to see if he's going to have to give an undertaking.
MR. YOUNG:
Q. So just to be clear, this is the commissioning energy essentially?
MR. GOULDING:
A. Yes, yeah.
MR. YOUNG:
Q. Okay, thank you.
MS. GLYNN:
Q. Noted on the record.
MR. GOULDING:
A. And I guess the other part of it was basically how we're operating CTs now as opposed to how we had envisioned our operating CTs in the -- when we developed our budgets in the fall of 2014.
MR. O'BRIEN:
Q. Okay. Well, take me through that.
MR. GOULDING:

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A. Okay.
MR. O'BRIEN:
Q. What's the difference in that?
MR. GOULDING:
A. I guess as part of the events during the first week in March, I think it's March the 4th, we had issues on our power system. It was mainly an Avalon event. We had a Holyrood unit off for maintenance. It was envisioned to be on -- be back online again at a time anyway before our morning peak of that morning, and we also -- and then when we realized that the Holyrood CT -- the Holyrood unit would not be available, we also had issues, I guess, getting the Holyrood CT online as well and that was -- we did send reports into the Board on those unit outages, I guess, and probably an overview of the -- so with those units not available, we had issues from a voltage perspective here on the Avalon. So there were -- from what I recall, we had to hold off some customers here on the Avalon for a period until we had enough generation to serve those customers.
MR. O'BRIEN:

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Q. And what was the issue with the CT at that time?
MR. GOULDING:
A. I recall an issue with a fuel valve that would have resulted in that unit not being available.
MR. O'BRIEN:
Q. Okay.
MR. GOULDING:
A. Now it did start up. We did get it on that morning afterwards, but it wasn't there right at the time in the morning peak.
MR. O'BRIEN:
Q. Okay. And to follow through, I guess, and where I think you were going, there's been a change now in how you're operating?
MR. GOULDING:
A. Yeah. Part of our learnings from that event and you know, way to increase the reliability of the system, like we recognized, I guess, that there was an event out there waiting to happen which was essentially the Holyrood unit not being available when required and prior to, I guess, this event, we would have held off on starting the CT until it was required.

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But right now, I guess, part of our learnings from this event is that when we know that there's a worst case outage out there that's going to result in a customer impact during the time say and I say a customer impact, we may have -- you know, there may be an outage that results in a transmission line overload that we have to hold off customers or there may be an issue with delivery point voltages as well. So we've developed, I guess, a set of load triggers now that tell us that we will be operating the CT in advance of these outages. So instead of -
MR. O'BRIEN:
Q. So is that part of your guidelines?
MR. GOULDING:
A. Pardon me?
MR. O'BRIEN:
Q. Is that part of your guidelines then?
MR. GOULDING:
A. It's not part of our weekly guidelines. They're more or less from an economic standpoint. But we do have daily reliability assessments of the power system and through those assessments, we take our load forecast

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and we take our generation availability and based on our load forecast -- it's primarily an Avalon requirement. So based on our Avalon load forecast, now we have load triggers that we'll start up the CT.

(12:00 p.m.)

MR. O'BRIEN:

Q. Okay. So those load triggers, are they built into like an application similar to your daily sort of load forecast that your group performs?

MR. GOULDING:

A. Yeah. Like these load triggers, they wouldn't normally change. Like we did load flows with no Holyrood units in operation, one unit, two unit and three units. So at each one of those -- at each one of these times, we know when the CT is required to be started to be able to withstand our worst case outage.

MR. O'BRIEN:

Q. And this is different than what the plan for the use of the CT was in 2014, is it?

MR. GOULDING:

A. That's correct.

MR. O'BRIEN:

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Q. Okay. And if we -- perhaps we can have a look at the August 2015 monthly report as well.

MS. GLYNN:

Q. We'll enter that as Information No. 16.

MR. O'BRIEN:

Q. Thank you. If we have a look at the month this year, I guess for August 2015, for the Holyrood CT, there's 7.2 gigawatt hours in that particular month.

MR. GOULDING:

A. That's correct.

MR. O'BRIEN:

Q. Was there something different happening in that month or is it one of these load triggers that caused it to run for that much in August?

MR. GOULDING:

A. There is something different in that there would have been a total planned outage at Holyrood. So ordinarily, we would have been operating a Holyrood unit right throughout the summer period. So in the first -- and I stand to be corrected, but I think in the first two weeks or two weeks plus in August, there was a total planned outage which meant that neither Holyrood unit was available. So we ran the CT

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essentially in place of the Holyrood unit. But what happens with the CT is we're able to turn it on, I guess, during -- prior to the peak and after the peak. So there wouldn't have been as much energy incurred by running the CT as opposed to the Holyrood unit.

MR. O'BRIEN:

Q. So in terms of what was going on in August then, there wasn't -- would you term this an emergency? It wasn't a peak issue at that time, was it?

MR. GOULDING:

A. It was a peak in that we ran it during the peak period of the day when we were exposed to an outage to one of the major lines coming into the Avalon. So we would have ran it during the high load period and in the event that there was a line outage, the CT would have been on and we wouldn't have had a line overload and we wouldn't have had to hold off our customers for a period.

MR. O'BRIEN:

Q. Okay. And when you decide to run the CT in terms of, I guess, dispatch and whoever makes the decision to run it, you've indicated that

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there are load triggers that you have. Is there any consideration for cost given to run that when you make that decision? How does that work?

MR. GOULDING:

A. There is in that like we -- our triggers, they're built around the economic breakpoint as well of running the CT versus an extra Holyrood unit. So, and we use 12 hours of CT operation as our breakpoint. So if there's a period that we see that we would be operating the CT for more than 12 hours, then we turn on a Holyrood unit instead, if it was available of course.

MR. O'BRIEN:

Q. And that's more cost effective approach, would it be, the Holyrood unit?

MR. GOULDING:

A. It is, up to a certain period of CT operation, or after a certain period of CT operation.

MR. O'BRIEN:

Q. After a certain period, okay. And in terms of -- I guess in terms of this deferral account, Hydro would be looking to recover the cost of running that CT. There's a band that's

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proposed of $500,000 in terms of around the deferral account. How long would you have to run the CT to get to that band?
MR. GOULDING:
A. Just to do the rough math, 33 cents per kilowatt hour, it's likely not that long.
MR. O'BRIEN:
Q. And when you say likely not that long, how long would that be? Best case scenario. We're not talking more than a couple of days or a couple of weeks?
MR. GOULDING:
A. 33 cents a kilowatt, so it's $330 a megawatt. I'm not able to do that math here now in my head, sorry.
MR. O'BRIEN:
Q. And maybe I'll ask you to give an undertaking just to provide that.
MR. GOULDING:
A. Yeah, sure.
MS. GLYNN:
Q. Noted on the record.
MR. O'BRIEN:
Q. And in terms of -- it appears you've described like a change in philosophy as to how to

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operate the CT or what it's going -- how it's going to fit into the generation plan. How did that change in philosophy come about? I mean, is that something you decided? Was it something decided by Mr. Henderson? Was there a group? How did that work?
MR. GOULDING:
A. Oh no, it was certainly decided on by a group. Mr. Henderson and Mr. Humphries certainly would have been aware of it and agreed with the change. It's basically, I guess, in recognition and in learnings of our March event and the customer impact that resulted from it.
MR. O'BRIEN:
Q. And we talked earlier about maintaining a certain level of reserves in terms of generation. Is the CT run from that perspective?
MR. GOULDING:
A. It would be, but the way it turns out, like, the Avalon is essentially the ruling system, so once we have it on to be able to respond, I guess, in the event of an outage to a piece of equipment, or worse case outage, then this

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also satisfies our spinning reserve requirements as well.
MR. O'BRIEN:
Q. I wonder whether or not you can answer this, in terms of the deferral account, if the Board were to grant Hydro's proposal, what would the incentive be to Hydro to dispatch resources more efficiently once you hit the $500,000.00 band?
MR. GOULDING:
A. I guess, as has been stated, any times, like, we still have a mandate to provide least cost reliable power, so, like, in this particular instance, like, we still have our daily meetings and part of that meeting is to determine how best to not only economically operate the power system, but - I'm sorry, to not only reliably operate the power system, but to economically operate the power system as well, and that plays into our decision making of whether or not to run a Holyrood unit or to run a standby unit.
MR. O'BRIEN:
Q. And in terms of the disposition of the balance that would be in the deferral account, I

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understand Hydro is proposing that that would be subject to Board approval on an annual basis, is that how that would work?
MR. GOULDING:
A. That's right. I believe in that schedule, I think it was the end of March, the end of the first quarter each year.
MR. O'BRIEN:
Q. Okay, and from your perspective, what sort of factors should the Board consider in whether or not the balance should be - how the balance should be dealt with?
MR. GOULDING:
A. I guess, as part of the report, the Board may ask that we provide an indication, like, a summary report of when gas turbines were ran and maybe even what the circumstances were.
MR. O'BRIEN:
Q. Okay. I wonder if we could go back to - maybe we don't have to do this, but just Information 9, actually. That's the 2015 generation planning report. One of the notes we talked about earlier from that combustion turbine project briefing was about the use of the CT as black start, in black start scenario. In

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JOHNSON, Q.C.:
Q. And also the cost that was incurred for doing that?
MR. GOULDING:
A. Sure.
MS. GLYNN:
Q. Noted on the record.
JOHNSON, Q.C.:
Q. I take it that ordinarily it would have been a Holyrood unit that would be doing the work that the CT was asked to do?
MR. GOULDING:
A. That's correct. Like I mentioned in my testimony yesterday, we have certain levels of Avalon load where it's more economic to operate a Holyrood unit rather than the CT.
JOHNSON, Q.C.:
Q. Right.
MR. GOULDING:
A. Like, when we're in a place where we foresee that we'd operate a CT more than 12 hours per day, then we would operate a Holyrood unit.
JOHNSON, Q.C.:
Q. I see, but typically - let's say this coming August, if the Holyrood units are running, you

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would use the Holyrood unit, not the CT, right?
MR. GOULDING:
A. That's correct.
JOHNSON, Q.C.:
Q. And what Holyrood unit is typically employed to deal with the summer load?
MR. GOULDING:
A. It would vary, I guess, depending on their maintenance schedule. Typically, although it's not firm and fast, ordinarily Unit 3 would be available during the summertime operation.
JOHNSON, Q.C.:
Q. Would it be possible to provide an undertaking indicating what it would have cost to have a Holyrood unit running instead to do the work that the CT did?
MR. GOULDING:
A. Yes.
MS. GLYNN:
Q. Noted on the record.
JOHNSON, Q.C.:
Q. Mr. Goulding, you mentioned yesterday that Hydro has a trigger built around an economic

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break point of running the CT versus running an extra Holyrood unit, and you said that Hydro uses 12 hours of CT operation as the break point, and I took from what you were saying yesterday that if there's a period where Hydro would be operating the CT for more than 12 hours, then you would turn on the Holyrood unit instead, and then you added "if one was available, of course".
MR. GOULDING:
A. That's correct.
JOHNSON, Q.C.:
Q. And I'm just wondering - first of all, I take it that if this unit had been available in Holyrood this past summer in August, Hydro would not have chosen to use the CT, right?
MR. GOULDING:
A. If the unit was available, then we would have stayed the same course that we did for the remainder of the summer and operate that unit, but there is -
JOHNSON, Q.C.:
Q. And why would you have stayed the course then?
MR. GOULDING:
A. Because it would have been more economic to

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operate the unit versus the CT.
JOHNSON, Q.C.:
Q. Yes, right, and why couldn't the Holyrood unit have been available in August?
MR. GOULDING:
A. Because there is a certain amount of maintenance that's required at the Holyrood plant every year that requires that all units be shut. There's a lot of assets out there that are common to all units that require that all units be shut such that they can be maintained and made ready for the upcoming period where the operation at Holyrood is starting to ramp up.
JOHNSON, Q.C.:
Q. So are you telling me that there's no way for Hydro to avoid a planned shutdown of all three units in the summertime in Holyrood?
MR. GOULDING:
A. There's no way to avoid a total plant outage as there is maintenance that requires that all units be turned off simultaneously.
JOHNSON, Q.C.:
Q. All the same time?
MR. GOULDING:

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A. Yes.
JOHNSON, Q.C.:
Q. But how did Hydro manage in other summers, didn't they have a unit available for any purpose?
MR. GOULDING:
A. We would have had a unit available for most - there would have still been times during a total plant outage that for a period a unit would not have been available.
JOHNSON, Q.C.:
Q. Just to understand that, Hydro schedules the maintenance, right?
MR. GOULDING:
A. That's correct.
JOHNSON, Q.C.:
Q. And this was planned maintenance that was going on in August?
MR. GOULDING:
A. That's correct.
JOHNSON, Q.C.:
Q. When all three were down?
MR. GOULDING:
A. Uh-hm.
JOHNSON, Q.C.:

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Q. And are you saying that it would be impossible to have one ready while there's planned maintenance going on on the other two units?
MR. GOULDING:
A. I don't say it's impossible. I'm not - I'm not overly familiar with what goes on inside the Holyrood plant in terms of their maintenance activities, but I can speak to the fact that during previous summers, there were periods that - although there were periods during that summer that all three units would not have been available because there are activities that they undertake that requires that all three units be made unavailable.
JOHNSON, Q.C.:
Q. Okay, so who's knowledgeable about what's doable and not as regards Holyrood maintenance of the units?
MR. GOULDING:
A. I would say the most knowledgeable would be the folks inside the Holyrood plant themselves.
JOHNSON, Q.C.:
Q. I see. Did you all or members of your panel, any one of you, have input as to the decision

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to run the CT in August at Holyrood?
MR. GOULDING:
A. Yes, that decision would have certainly been made through our area. The difference this August, I guess, as opposed to previous summers would have been again our learnings from our March 4th event where we would have - we wouldn't have ran our gas turbines during the total plant outage of previous summers. The gas turbine would have been available and ready, but we wouldn't have started the unit until we got into an outage that required it.
JOHNSON, Q.C.:
Q. So you're running it just in case?
MR. GOULDING:
A. That's correct.
JOHNSON, Q.C.:
Q. And is there a lack of confidence in the ability to turn this CT on and off and get it going in a reasonable period of time?
MR. GOULDING:
A. It's not a lack of confidence. I guess, like, a part of this learning and where we are, is we don't operate the systems such that a single element outage, such as a transformer -

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I'm sorry, a transmission line or a generator outage is going to result in a customer impact, so we have the CT on in advance now to respond to it.
JOHNSON, Q.C.:
Q. I see, and is that a utility practice followed elsewhere to take that type of action?
MR. GOULDING:
A. I don't know what research was actually done in our area, but certainly, you know, I would expect that most jurisdictions would not operate their power system such that they're exposed to an N-1 outage. Now other jurisdictions may have other ways to respond to it. Like, where we're isolated, we don't have the opportunity here to draw on our neighbours, and, you know, other jurisdictions may have a transmission system that's robust enough to withstand a single element outage, so I would expect that most jurisdictions would operate in the same vein, but in terms of how they respond, whether it's standby or reserve sharing arrangements, that sort of thing, I don't know.
(9:30 a.m.)

JOHNSON, Q.C.:
Q. You indicated that Hydro has, I guess, made a calculation of an assessment that there is a 12 hour break point, and when was this studied and settled upon as being the break point?
MR. GOULDING:
A. That would have been following the March 4th event that we undertook a review, and at that point we realized that it was prudent to start our standby units in advance of outages that would result in a customer outage. So what we did is we took a typical load shape during the period of, say, three unit operation, two unit, one unit, and what we did is we - there's a certain threshold in this imposed on that load shape that we determined, you know, it would be more economic to operate a CT during certain periods than it would be a Holyrood unit, and that threshold is now our - the point that we determine and we have daily reliability meetings where we have a one week outlook on our load and reserves, and part of our reliability assessment is to assess the Avalon reserves. So at that point, we advise our gas turbine folks if we need to operate

the CT during periods of that week.
JOHNSON, Q.C.:
Q. So in terms of the - there's been an actual calculation done supporting the 12 hour rule, if you will?
MR. GOULDING:
A. There has been load flows done, yes.
JOHNSON, Q.C.:
Q. Okay, and could Hydro file that analysis showing how that break even was arrived - or that break point was arrived at?
MR. GOULDING:
A. I think that can be filed.
JOHNSON, Q.C.:
Q. Thank you.
MS. GLYNN:
Q. Noted on the record.
JOHNSON, Q.C.:
Q. Okay, and has Hydro, like, actually established a policy that's been reduced to writing as regards when the CT is to be used?
MR. GOULDING:
A. We have - again I go back to our March 4th event. Part of the learnings there were we developed a protocol for Avalon reserves that

basically mirrors the protocol that was already in place for island reserves. So in that there's a step by step sequence that our ECC operators follow in the event that there's reserve issues on the Avalon. So they would follow that sequence and as part of that sequence would be the start up of our standby on the Avalon.
JOHNSON, Q.C.:
Q. So if there is something in writing on that, can that be provided as well?
MR. GOULDING:
A. Yes, we can file certainly that instruction.
JOHNSON, Q.C.:
Q. All right.
MS. GLYNN:
Q. Noted on the record.
JOHNSON, Q.C.:
Q. Thank you very much. I think this was you as well yesterday, Mr. Goulding, and that was a discussion about recovering variances in costs incurred in connection with the fuel cost associated with operating the CT. Do you recall a discussion of there being a $500,000.00 band, etc, and Newfoundland Power

asked you for undertakings as to how long it would take you to get up to $500,000.00, etc, and Mr. O'Brien questioned what incentive would Hydro be left with other than the $500,000.00, what incentive it would be left with to dispatch resources more efficiently, you know, once you hit the $500,000. 00 threshold, and I think in your reply you mentioned that Hydro has a least cost mandate, etc, etc, but I take it that would not be to say that you would disagree that the actual financial incentive is taken away by way of this mechanism other than the $500,000. 00 exposure?
MR. GOULDING:
A. I think the financial exposure is certainly taken away.
JOHNSON, Q.C.:
Q. Yeah.
MR. GOULDING:
A. I speak for the operators of the power system, like, we do have a mandate to operate our power system as reliably and economic as is possible, so certainly we would - even in light of a deadband, a deferral account, we

would still have our daily reliability assessments and we would still have a keen eye out towards what's the best way to reliably meet our criteria, and what's the most economic way, and this is why we went down the road of developing these thresholds or levels of load on the Avalon that guide us to economically operate the system.

JOHNSON, Q.C.:
Q. And customers are paying you guys to actually go through analysis like that, manage those considerations presently, right?

MR. GOULDING:
A. That's correct. It's essentially a cost of reliably operating the power system. I would say that it's really - it's a different generating unit, but it's not a lot different than where we've been, say, in the last five or six years or seven years since we've had Holyrood reduced to minimum operation. You know, for all intents and purposes, the driver for operating Holyrood units, although there may be portions of the energy that would have been required to augment our hydro generation and storages, you know, the primary driver for

operating Holyrood units for the last six or seven years has been from a reliability standpoint as well. So that has added to increased fuel costs that have flowed through the RSP as well.

JOHNSON, Q.C.:
Q. Yeah, but I take it, and I just want to clarify, that the financial incentive in the financial sense is not there with the deferral account beyond the $500,000.00?

MR. GOULDING:
A. I speak from an operating perspective -

JOHNSON, Q.C.:
Q. I understand.

MR. GOULDING:
A. And we would certainly maintain our mandate to make sure that the right units are on at the right time, and that would ultimately make sense from a financial perspective as well.

JOHNSON, Q.C.:
Q. Just turning for a second to black start, Mr. Humphries, and I think this would be more for you. You indicated yesterday that the intent of the new 123 megawatt CT unit is to provide black start, but you indicated that has not

been tested and proven to this point.

MR. HUMPHRIES:
A. That's correct.

JOHNSON, Q.C.:
Q. And who's responsible for testing and proving a black start capability?

MR. HUMPHRIES:
A. Well, it would be a part of the asset owner, a combination of the asset owner and arranging it with system operations to find a window when it can adequately be tested.

JOHNSON, Q.C.:
Q. Okay, and the asset owner is Hydro?

MR. HUMPHRIES:
A. Yes.

JOHNSON, Q.C.:
Q. And is that a big process to get that testing and proving done?

MR. HUMPHRIES:
A. Well, it's turned into a bit of a process this summer because in order to test it, (a) we needed a unit in Holyrood to be able to test, to start, and with the maintenance windows that we've had this year, the opportunities were limited to have a unit available that we

could test the turbine, and in addition to that because to full test the unit, we need to put isolations on the system to ensure that there was no support coming from the system to start the turbine, and so that involved opening certain 230 kV transmission lines and theoretically putting the system at a level of exposure. We were in a situation through most of the summer where we had one unit running at Holyrood and the other two out on maintenance. We went - there was an opportunity - the first opportunity would have been with the restart of Unit 2, I believe - sorry, number 3 when it came back from maintenance, and that would have been in August. Also at those times there was a number of system elements on the Avalon Peninsula out of service for maintenance, and when we got to the point of the window of scheduling that start up, it was not safe to actually take the transmission out of service, do the black start, we were putting customer load at risk. The next window of opportunity would have been in last September, the 25th or 26th of September, when Unit 2 was coming back, and that window was

Evidence to the Amended 2015 Cost Deferral Application

NEWFOUNDLAND AND LABRADOR HYDRO

November 12, 2015

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1.0 BACKGROUND

On January 28, 2015 Hydro filed an application with the Board (the 2015 Interim Rates Application) seeking approval of adjustments to its customer rates to provide interim rate relief effective March 1, 2015, in advance of conclusion of its General Rate Application (GRA). On May 8, 2015 the Board issued Order No. P.U. 14(2015) (the 2015 Interim Rates Order) directing Hydro to file a revised Schedule of Rates, Tolls and Charges and RSP Rules to become effective July 1, 2015 with evidence showing the impacts on customers and Hydro incorporating the findings in the 2015 Interim Rates Order. On June 5, 2015, Hydro filed a Revised Compliance Application reflecting the direction of the Board as provided in the 2015 Interim Rates Order. Approval of customer rates changes, reflecting the determinations set out in Order No. P.U. 14 (2015), was forecast to result in a net income deficiency based upon the 2015 Test Year of $41.8 million as a result of delayed rate implementation beyond January 1, 2015.

On July 23, 2015, Hydro filed a 2015 Cost Deferral Application requesting a cost deferral in amount of $20.0 million to reduce Hydro's forecast 2015 net income deficiency. Approval of the original 2015 Cost Deferral Application would have provided for a forecast net income of $11.4 million based upon the forecast 2015 Test Year. This amount was $21.8 million less than the proposed 2015 Test Year net income of $33.2 million. The original 2015 Cost Deferral Application did not anticipate the final GRA Board order being delayed beyond 2015.

The hearing portion of Hydro's GRA began on September 9, 2015. The hearing process is ongoing. Therefore, Hydro does not expect the Board will be in a position to make final determinations on the GRA before the conclusion of 2015. As such, Hydro is filing an Amended 2015 Cost Deferral Application to address the 2015 financial impacts of the delayed conclusion of Hydro's GRA beyond 2015. Approval of the Amended 2015 Cost Deferral Application is required to provide Hydro the opportunity to recover its costs, including a reasonable return on rate base for 2015, as required by Section 80 of the Public Utilities Act.

2.0 2015 NET INCOME DEFICIENCY

The updated forecast of the 2015 Net Income Deficiency is primarily related to three areas: (i) the 2015 net income deficiency resulting from billing customers for the first 6 months of 2015 based on 2007 Test Year base rates; (ii) the additional 2015 costs incurred by Hydro as a result of operating the Rate Stabilization Plan (RSP) relative to the 2007 Test Year; and (iii) the additional 2015 supply costs which Hydro proposed in the Amended GRA be recovered through new supply cost recovery mechanisms.

The updated forecast net income deficiency for 2015 is approximately $60.5 million based on a forecast net loss of $30.8 million. Hydro's Amended 2015 Cost Deferral Application provides proposals to the Board to address the forecast 2015 net income deficiency in a reasonable manner which does not disadvantage customers.

2.1 Delayed 2015 Rate Implementation

Due to the delayed implementation of 2015 Test Year rates, Hydro will not have the opportunity to recover its full test year revenue requirement in 2015. While the approval of interim rates effective July 1, 2015 has mitigated a portion of this impact, there still remains a material net income deficiency forecast for 2015.

Table 1 shows that the impact of delayed implementation of rates in 2015, adjusted for opening balance rate base reductions for 2015, is $36.8 million.

Table 1

Line No.	Particulars	$000's	
1	2015 Test Year Rates Net Income	33,232	[1]
2	2015 Existing Rates Net Income	(34,583)	[2]
3	Net Income Deficiency	67,815	[3]
4	Less Impact of Interim Rates	(26,000)	[4]
5	Gross Deficiency	41,815	[5]
6	Rate Base Adjustment	(5,000)	[6]
7	Net 2015 Deficiency	36,815	[7]

The $5.0 million revenue requirement reduction in line 6 of Table 1, relative to the $41.8 million deficiency based on the 2015 Test Year, reflects lower actual capital additions in 2014 when compared to the 2014 Test Year. The requirement for these rate base adjustments for 2015 were outlined in Grant Thornton's Financial Consultants Report.[8]

The adjustment to revenue requirement to reflect a lower opening balance in rate base for the 2015 Test Year is made because these assets were not in service at year-end 2014. However, this rate base adjustment is appropriate for the 2015 Cost Deferral only and not for the purpose of determining revenue requirement for 2016. These assets are forecast to be in service in 2015 and therefore, will be used and useful in the provision of service to customers for all of 2016. As such, it is appropriate that Hydro should be given the opportunity to earn a return on these assets in 2016.

[1] 2013 Amended General Rate Application, Finance Schedule I, Page 1 of 11, Line 17.
[2] 2013 Amended General Rate Application, Finance Schedule II, Page 1 of 1, Line 31.
[3] Line 1 minus Line 2.
[4] Evidence to Revised Compliance Filing dated June 4, 2015, Page 11, Table 9.
[5] Line 3 plus Line 4.
[6] Rate base adjustment per PUB-NLH-487.
[7] Line 5 plus Line 6.
[8] See page 115 of Grant Thornton's report to the Board dated June 12, 2015 and Hydro's response to PUB-NLH-487.

Hydro proposes the Board approve a cost deferral for 2015 which offsets the net income deficiency from delayed rate implementation in 2015. The recovery of the actual amount resulting from delayed implementation of final customer rates will be dealt with in a future order of the Board subsequent to conclusion of the GRA.

2.2 RSP Test Year

The RSP inputs (e.g., load forecast, fuel cost forecast, Holyrood fuel conversion rate, rates) that are currently in effect for use in the determination of Hydro's fuel costs and RSP interest are calculated, on an interim basis, in accordance with the 2007 Test Year Cost of Service (COS) estimates in relation to actual fuel costs. Hydro's Amended Application is based on a 2015 Test Year. Upon approval of the 2015 Test Year, the RSP balances for 2015 will be recalculated based on the Board approved RSP inputs from the 2015 Test Year COS. Given that the Board's final order will not be implemented in 2015, Hydro will incur an estimated increase in 2015 interest costs of $7.6 million as a result of the use of 2007 Test Year RSP inputs rather than the 2015 Test Year RSP inputs.[9]

Table 2 provides the 2015 forecast year-end RSP balances using the 2015 Test Year COS inputs and Table 3 provides the 2015 forecast year-end RSP balances under the 2007 Test Year COS inputs. Table 4 provides a comparison of the 2015 interest expense under both scenarios.

[9] For the purposes of the forecast interest expense, Hydro assumed the 2015 Test Year will be based on a No. 6 fuel cost of $64.41 per barrel ($CDN) consistent with the correspondence provided to the Board in the Island Industrial Customer (IIC) Interim Rates Application filed on October 28, 2015. The RSP energy rates for Newfoundland Power and IIC were also assumed to reflect the revised No. 6 fuel price. Hydro also assumed the 2014 Deficiency will be recovered through the Hydraulic Variation Account balance as of December 31, 2014.

Table 2
($000's)

Rate Stabilization Plan
Overall Summary
2015 COS Estimates
31-Dec-15

	A Hydraulic Balance	B Utility Balance	C Industrial Balance	D Segregated Load Balance	E Utility RSP Surplus	F Industrial RSP Surplus	G Total
Balance before interest	(19,760)	(14,025)	443	(41,085)	(124,014)	(4,118)	(202,558)
Interest	-	(2,635)	(65)	(2,664)	(8,454)	(281)	(14,099)
Balance	(19,760)	(16,660)	378	(43,749)	(132,468)	(4,399)	(216,657)

Table 3
($000's)

Rate Stabilization Plan
Overall Summary
2007 COS Estimates
31-Dec-15

	A Hydraulic Balance	B Utility Balance	C Industrial Balance	D Segregated Load Balance	E Utility RSP Surplus	F Industrial RSP Surplus	G Total
Balance before interest	(57,942)	(60,788)	1,082	(55,265)	(124,014)	(2,999)	(299,926)
Interest	-	(8,412)	(296)	(3,405)	(9,337)	(293)	(21,744)
Balance	(57,942)	(69,201)	787	(58,670)	(133,351)	(3,292)	(321,670)

Table 4
($000's)

Rate Stabilization Plan
Interest Adjustment
2007 COS Base vs. 2015 COS Base
31-Dec-15

	A Hydraulic Balance	B Utility Balance	C Industrial Balance	D Segregated Load Balance	E Utility RSP Surplus	F Industrial RSP Surplus	G Total
Interest expense - 2015 COS Base	-	(2,635)	(65)	(2,664)	(8,454)	(281)	(14,099)
Interest expense - 2007 COS Base	-	(8,412)	(296)	(3,405)	(9,337)	(293)	(21,744)
Interest adjustment	-	5,777	230	741	883	12	7,644

Table 4 demonstrates that as a result of the materially higher forecast 2015 year-end RSP balances based on the RSP inputs from the 2007 Test Year COS, Hydro will incur an additional $7.6 million in interest in 2015.

Board approval of the 2015 Test Year in 2016 and the subsequent updating of the RSP based on the 2015 Test Year will result in a reversal of the increased 2015 interest expense to provide an interest expense savings in 2016. The delay in implementation of the 2015 Test Year for purposes of determining the RSP balance results in a timing difference that spans Hydro's fiscal year-end. Due to the materiality of the impact on 2015 financial results and recognizing the cost will be reversed in 2016, Hydro proposes to record the additional interest expense in a deferral account for 2015.

2.3 Supply Cost Variances

Hydro is currently forecast to incur materially higher supply costs in 2015 compared to the 2015 Test Year forecast. In the Amended Application, Hydro proposed three new deferral accounts to deal with variances from the Test Year forecast of supply costs. These included the Isolated Systems Supply Cost Variance Deferral Account, the Energy Supply Cost Variance Deferral Account and the Holyrood Conversion Rate Deferral Account. The delay in implementation of the 2015 Test Year beyond year-end 2015 also results in Hydro's 2015 financial reporting reflecting the use of the 630 kWh per barrel Holyrood fuel conversion rate approved for the 2007 Test Year. The difference between the Holyrood fuel conversion rate proposed for the 2015 Test Year and the conversion rate approved for the 2007 Test Year results in a material increase in the Holyrood fuel costs that will be incurred in 2015.

Table 5 shows the forecast 2015 year-end balances if the proposed deferral accounts were approved for implementation effective January 1, 2015 plus the forecast fuel cost impact of delayed implementation of the proposed test year change in the Holyrood fuel conversion rate.[10]

Table 5

Line No.	Particulars	$000's (Due To)/From Customers
1	Isolated Systems Supply Cost Variance Deferral Account	(955)
2	Energy Supply Cost Variance Deferral Account	7,064
3	Holyrood Conversion Rate Deferral Account	2,418
4	Change in Test Year Holyrood Fuel Conversion Rate	4,214
5	Proposed 2015 Supply Cost Deferral	12,741

The deferral account balances in Table 5 have been calculated in a manner consistent with the proposed deferral mechanisms in Hydro's Amended Application. Due to the materiality of the impact on 2015 financial results and recognizing that costs are not controllable by Hydro and were proposed for recovery in the Amended Application, Hydro proposes to record the additional supply costs in a deferral account for 2015. The following sections provide more detail on each of the supply cost deferral amounts provided in Table 5.

2.3.1 Isolated Systems Supply Cost Variance Deferral Account

The Isolated Systems Supply Cost Variance Deferral Account is forecast to provide savings of approximately $1.0 million to customers in 2015. These savings reflect a lower cost of No. 2 fuel used in serving Hydro's Isolated Systems than the forecast cost reflected in the 2015 Test Year. Appendix B to this evidence provides the calculation of the forecast 2015 year-end balance in the Isolated Systems Supply Cost Variance Deferral Account.

[10] Forecast amounts reflect actual results to August 31, 2015.

2.3.2 Energy Supply Cost Variance Deferral Account

The Energy Supply Cost Variance Deferral Account is forecast to have a balance of approximately $7.1 million at year-end of 2015. This balance is primarily due to variances in hydraulic and gas turbine production. Decreased hydraulic production, primarily on the Nalcor Exploits system, is being replaced by more expensive thermal generation. The replacement of low cost purchases with Holyrood generation has resulted in a significant increase in supply costs for 2015.

In addition, operational requirements have increased production at the Holyrood Combustion Turbine (Holyrood CT) in 2015. Production at the Holyrood CT is forecast to increase by approximately 20.5 GWh more than the 2015 Test Year forecast in order to increase system reliability on the Avalon Peninsula.[11] This increased production at the Holyrood CT, in combination with lower hydraulic production at Nalcor Exploits, is the other primary driver of the forecast balance for 2015. The forecast balance of $7.1 million in this account reflects the proposed cost variance threshold of $0.5 million which would accrue as a supply cost to Hydro.

Increased production at the Holyrood CT resulted in Hydro operating in a manner that enabled more reliable service to customers throughout 2015. In addition, consistent with the operation of the RSP, levels of hydraulic production are, to a great degree, beyond management’s control. Hydro submits that both sources of variance result in a material increase in the cost of providing reliable service to customers and were prudently incurred. Appendix C to this evidence provides the calculation of the forecast 2015 year-end balance in the Energy Supply Cost Variance Deferral Account.

[11] See testimony from Hydro’s 2013 GRA Amended Application, October 20, 2015, Pages 131 through 133.

2.3.3 The Holyrood Conversion Rate Deferral Account

The Holyrood Conversion Rate Deferral Account is forecast to have a balance of $2.4 million.[12] This balance is due to a forecast fuel efficiency factor of approximately 597 kWh/bbl versus 607 kWh/bbl proposed for the 2015 Test Year. The decline in fuel conversion performance is primarily due to changes external to the operation of the Holyrood Thermal Generating Station (Holyrood TGS). There have been lower production requirements at the Holyrood TGS as a result of reduced system loads, higher energy purchases, and higher levels of hydraulic generation.[13] Appendix D to this evidence provides the calculation for the forecast 2015 year-end balance in the Holyrood Conversion Rate Deferral Account.

2.3.4 Change in Test Year Holyrood Conversion Rate

Hydro is currently using a Holyrood fuel conversion rate of 630 as approved in the 2007 GRA. Fuel related expenses that are incurred as a result of achieving lower fuel conversion rate are not stabilized through the normal operation of the RSP and are priced at the 2007 Test Year fuel cost. The fuel cost variance between the forecast conversion rate of 597 kWh/bbl and the 2015 Test Year proposed conversion rate of 607 kWh/bbl are reflected in the Holyrood Conversion Rate Deferral Account noted above. However, the variance between the proposed conversion rate of 607 kWh/bbl in the 2015 Test Year and the conversion rate of 630 kWh/bbl in the 2007 Test Year is estimated to be $4.2 million in 2015. This material fuel cost difference arises due to the timing of the approval of the 2015 GRA.

As with the RSP interest expense, Board approval of the 2015 Test Year in 2016 and the subsequent updating of the RSP based on the 2015 Test Year will result in a reversal of the increased fuel cost in 2015 to provide a fuel cost savings in 2016. Due to the materiality of the impact on 2015 financial results and recognizing the cost will be reversed in 2016, Hydro

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[12] The 2015 Test Year assumes a fuel efficiency factor of 607 kWh/bbl. Hydro's forecast estimates that for the 2015 Test Year the Board will approve a No. 6 fuel cost of $64.41 ($CDN) per barrel.
[13] See Hydro's Amended Application, Section 2: Regulated Activities, page 2.74.

proposes to record the additional $4.2 million in fuel cost expense in a deferral account for 2015. Appendix E to this evidence provides the calculation of the forecast 2015 fuel cost impact of using the 2007 Test Year conversion rate for 2015.

3.0 OTHER 2015 ADJUSTMENTS

A final order of the Board on Hydro's GRA is not expected before the conclusion of Hydro's 2015 financial year-end. As such, Hydro's is requesting interim approval of several items for financial reporting and planning purposes.

3.1 General Rate Application Costs

Hydro is forecast to incur $1.2 million in 2015 associated with external GRA hearing costs. In Hydro's Amended Application, these costs were proposed to be deferred and recovered over a period of three years.[14] Without an order to permit the deferral of these costs, Hydro will be required by International Financial Reporting Standards (IFRS) to expense these costs in 2015. Should the Board then approve any amount of these costs for deferral in the final GRA order, Hydro would be deferring costs already expensed in the previous fiscal year. Such a scenario would result in an overstatement of Hydro's 2015 expenses and a corresponding understatement in 2016. Hydro proposes that deferral of these costs for 2015, with recovery to be determined in a future order of the Board, would provide for more accurate annual financial reporting of Hydro's results.

[14] See Hydro's 2013 Amended Application, Section 3: Finance, Page 3.22, Lines 7-14.

3.2 Settlement Agreement

On August 14, 2014 Hydro entered into an all party settlement agreement (the Settlement Agreement). This agreement, among other items, provided for: specific deliverable dates for reports from Hydro and the filing of Hydro's next GRA; adjustments to Hydro Asset Retirement Obligation (ARO) costs in the 2015 Test Year; accounting treatment for Employee Future Benefits (EFBs); and deferral of Conservation Demand Management (CDM) costs. Hydro is requesting interim approval of this agreement to provide for greater certainty regarding Hydro's year-end financial reporting, and agreed upon deliverable dates.[15] Appendix H provides Hydro's 2015 CDM Report providing support for the proposed cost deferral.

In the Settlement Agreement, Hydro committed to providing a number of reports and applications by specific agreed upon dates. Specifically, Hydro committed to a marginal cost study, a cost of service methodology report, a report on the RSP, and a filing date for its next General Rate Application. Approval of the Settlement Agreement on an interim basis will provide Hydro a degree of certainty with respect to these deliverable dates.

The Settlement Agreement states that Hydro's 2015 Test Year ARO costs are to be reduced by $0.6 million.[16] The impact of this adjustment on Hydro's forecast 2015 results is shown in Appendix A to this Evidence. Interim approval of the ARO cost reduction will reduce Hydro's net income deficiency for 2015.

In accordance with Board Order P.U. 13 (2012), Hydro has effectively deferred all actuarial gains and losses associated with employee future benefits. In the Amended Application, Hydro has proposed to include a portion of these costs in revenue requirement.[17] Without an interim order of the Board in 2015, these costs will remain deferred thereby understating Hydro's 2015 expenses. A final GRA Order on this matter in 2016 without recognition of these costs in 2015

[15] See August 14, 2015 Settlement Agreement.
[16] See August 14, 2015 Settlement Agreement, Page 2, Item 9.
[17] 2013 Amended Application, Section 3: Finance, Page 3.51, Section 3.9.2 Employee Future Benefits.

will result in a corresponding overstatement of these expenses in 2016. Hydro submits that interim approval of this settled issue will provide for more accurate financial reporting of Hydro's results in both 2015 and 2016.

The Settlement Agreement states that the parties agree with Hydro's proposal to defer and amortize CDM costs.[18] Deferral of these costs would be consistent with the Settlement Agreement and past practice of the Board for the years 2009 through 2014. Without an interim order of the Board to defer these costs, Hydro will be required under IFRS to expense $1.2 million in CDM costs in 2015, thereby overstating Hydro's expenses in 2015. The proposed treatment of CDM costs in the Settlement Agreement is consistent with the methodology approved for Newfoundland Power in dealing in CDM costs.

4.0 SUMMARY

Table 6 provides a summary of the proposed 2015 cost deferral.

Table 6

Line No.	Particulars	$ Millions
1	2015 Delayed Rate Implementation	36.8
2	2015 Supply Costs	12.7
3	2015 RSP Interest	7.6
4	Other Items	3.4 [18]
5	Proposed 2015 Cost Deferral	60.5

Approval of the proposed cost deferral of $60.5 million will provide Hydro the opportunity to earn a reasonable return in 2015 and maintain the Board's ability to test 2015 costs throughout the GRA. Of the proposed $60.5 million proposed deferral, $11.8 million will be disposed of through updating the RSP for the 2015 Test Year upon final approval of new customer rates.[20]

[18] August 14, 2014 Settlement Agreement, Page 4, Item 17.
[19] Other items include EFB of $1.6M, CDM Costs of $1.2M, GRA Costs of $1.2M, less ARO of $0.6M.
[20] RSP Interest Adjustment of $7.6 million plus Change in Test Year Holyrood Fuel Conversion Rate of $4.2 million.

The recovery approach to the remaining $48.7 million would subject to a future order of the Board upon finalization of the actual 2015 net income deficiency.

Hydro submits that such a deferral account would be consistent with past practice of the Board and does not disadvantage customers. The Board, in Order No. 58 (2014), approved the creation of a deferral account in relation to delayed recovery of Hydro's proposed 2014 revenue requirement.

Hydro's original 2015 Cost Deferral Application proposed a 70% recovery of the forecast 2015 Net Income Deficiency resulting from delayed rate implementation. The original 2015 Cost Deferral Application did not anticipate the final GRA Board Order being delayed beyond 2015.

Appendix A to this evidence includes Hydro's most recent 2015 forecast. This forecast demonstrates a material net income deficiency for 2015. If the Board does not approve any of the items in the 2015 Cost Deferral Application, Hydro is forecasting a net loss of $30.8 million in 2015 and a return on rate base of 3.56%.

Table 7 provides Hydro's forecast net income and return on rate base in 2015 under a range of recovery percentages applied to the total 2015 revenue deficiency relative to the Amended Application.[21]

Table 7

Line No.	Scenario	Deferred Recovery ($ Millions)	2015 Net Income ($ Millions)	2015 Return on Adjusted Rate Base (%)
1	70% Recovery	60.6	3.8	5.25%
2	80% Recovery	69.2	12.4	5.71%
3	90% Recovery	77.9	21.1	6.17%
4	100% Recovery	86.5	29.7	6.62%

[21] Table 7 includes the $26 million forecast additional revenue from rates in 2015 resulting from Order No. P.U. 14 (2015) and related orders. For example, 80% recovery equals 80% x ($60.5 million + $26.0 million) = $69.2 million.

Approval of all of Hydro's proposals in the 2015 Cost Deferral Application would result in a forecast net income of $29.7 million in 2015. This net income for 2015 would provide a forecast return on rate base of 6.62% which is at the bottom of the proposed range of return on rate base of 6.62% to 7.02% in the 2015 Test Year. As shown in Table 7, approval of a recovery percentage below 100% would not provide Hydro the opportunity to earn a reasonable return on rate base in 2015.

Hydro is also proposing an interim order of the Board to deal with several issues which would otherwise negatively impact the reporting of Hydro's, 2015 year-end financial results, as a result of the issuing of a final GRA Order beyond year-end 2015. Further, interim approval of settled issues will allow for more accurate financial reporting of Hydro's regulated financial results.

Board approval for the proposed cost deferral combined with the Interim approval of the Settlement Agreement will ensure that Hydro is provided the opportunity to recover costs incurred in the provision of reliable service to customers and the opportunity to achieve a reasonable return on rate base in 2015. Hydro will ultimately recover from customers the costs fully tested by the Board through final customer rates.

Appendix A
Newfoundland and Labrador Hydro
2015 Forecast vs. 2015 Test Year

Line No.		Actuals to August 2015 Forecast	2015 Test Year	Variance	Forecast Return on Rate Base [(2)]	Note
1	**REVENUE**					
2	ENERGY SALES	545.5	660.1	(114.6)		**1**
3	OTHER REVENUE	2.1	2.4	(0.3)		
		547.6	662.5	(114.9)		
4	**EXPENSES**					
5	OPERATING EXPENSES					
6	Salaries and benefits	91.2	88.9	2.3		**2**
7	System equipment maintenance	28.2	26.8	1.4		**3**
8	Office supplies and expenses	2.8	2.8	-		
9	Professional services	11.9	9.5	2.4		**4**
10	Insurance	2.6	2.6	-		
11	Equipment rentals	3.5	3.1	0.4		**5**
12	Travel	3.9	3.7	0.2		
13	Miscellaneous expenses	6.0	5.7	0.3		
14	Building rental and maintenance	1.3	1.2	0.1		
15	Transportation	1.7	2.3	(0.6)		**6**
16	Cost recoveries	(8.9)	(8.4)	(0.5)		**7**
17	NET OPERATING EXPENSES	144.2	138.2	6.0		
18	LOSS ON DISPOSAL OF PPE	6.0	4.1	1.9		**8**
19	OTHER EXPENSE	2.0	2.2	(0.1)		
20	FUELS	209.2	269.8	(60.6)		**9**
21	POWER PURCHASED	61.5	63.3	(1.8)		**10**
22	AMORTIZATION	63.2	64.7	(1.5)		**11**
23	INTEREST	92.3	87.1	5.2		**12**
		578.4	629.2	(50.8)		
24	**NET (LOSS)/INCOME WITHOUT REGULATORY ADJUSTMENTS**	**(30.8)**	**33.2**	**(64.1)**	**3.56%**	
25	2015 Delayed Rate Implementation Deferral	36.8	-	36.8		
26	**NET INCOME WITH PROPOSED 2015 TEST YEAR RATES**	**6.0**	**33.2**	**(27.3)**	**5.69%**	
27	Isolated Systems Supply Cost Deferral Account	(1.0)	-	(1.0)		
28	Energy Supply Cost Variance Deferral Account	7.1	-	7.1		
29	Holyrood Conversion Rate Deferral Account	2.4	-	2.4		
30	Change in Test Year Holyrood Fuel Conversion Rate	4.2	-	4.2		
31	**NET INCOME WITH TY RATES & SUPPLY COST RECOVERY**	**18.7**	**33.2**	**(14.6)**	**5.98%**	
32	RSP Interest Adjustment	7.6	-	7.6		
33	Employee Future Benefits Actuarial Loss [(1)]	1.6	-	1.6		
34	CDM Cost Deferral [(1)]	1.2	-	1.2		
35	GRA Cost Deferral	1.2	-	1.2		
36	ARO Adjustment per Settlement Agreement [(1)]	(0.6)	(0.6)	-		
37	**NET INCOME WITH PROPOSED 2015 COST DEFERRAL**	**29.7**	**32.6**	**(3.0)**	**6.62%**	

[(1)] August 14, 2015 Settlement Agreement.

[(2)] Hydro's 2015 Test Year Average Rate Base $1,802.0 million per Hydro's Amended Application, Finance Schedule I, Page 5 of 11, Line 21 less an opening Rate Base adjustment of $148.0 million (average of $74.0 million) per PUB-NLH-487.

[(3)] Totals may vary due to rounding differences.

Note	Description	Variance Explanation
1	Energy sales	Revenue from energy sales have decreased by $114.6 million from the 2015 Test Year primarily due to delayed implementation of 2015 Test Year rates.
2	Salaries and benefits	Salaries and benefits have increased by $2.3 million from the 2015 Test Year. The primary driver is an increase in employee future benefits expense of $1.1 million and an increase of $0.7 million associated with new union agreement and other benefit costs.
3	System equipment maintenance	System equipment maintenance has increased by $1.4 million from the 2015 Test Year to the 2015 Forecast due to increased maintenance on Holyrood units 1, 2 and 3.
4	Professional services	Professional services increased by $2.4 million from the 2015 Test Year to the 2015 Forecast primarily due to an increase in regulatory activity of $2.0 million and CDM program costs of $0.5 million.
5	Equipment rentals	Equipment rental costs have increased by $0.4 million from the 2015 Test Year to the 2015 Forecast primarily due to rental of backup diesel generation in TRO Central and Northern.
6	Transportation	Transportation costs have decreased by $0.6 million from the 2015 Test Year to the 2015 Forecast primarily due to fuel price savings of $0.2 million, an increase in charges to capital of $0.2 million and lower aircraft costs of $0.1 million due to new a contract in place.
7	Cost recoveries	Cost recoveries have increased by $0.5 million from the 2015 Test Year to the 2015 Forecast primarily due to additional administration fee recovery.
8	Loss on Disposal of PPE	Loss on disposal costs have increased by $1.9 million from 2015 Test Year to the 2015 Forecast primarily due to a $1.2 million increase in costs associated with asset disposals, as well as an increase in removal costs of $0.7 million. The disposals relate to a supplemental capital application for Hardwoods Engine Overhaul resulting in an unbudgeted $0.7 million asset disposal, combined with disposals related to capital work carried over from 2014.
9	Fuels	Fuel costs have decreased by $60.6 million from the 2015 Test Year primarily due to delay in implementation of customer rates to reflect the 2015 Test Year fuel price, partially offset by additional supply costs at the Holyrood Thermal Generating Station as well as the Holyrood Combustion Turbine.
10	Power Purchased	Power Purchased has decreased by $1.8 million from 2015 Test Year to the 2015 Forecast primarily due to $1.4 million in lower production at Exploits, Star Lake and Rattle Brook as well as $0.4 million in lower wind production from St. Lawrence.
11	Amortization	Amortization costs have decreased by $1.5 million from 2015 Test Year to the 2015 Forecast primarily due to delay in the Holyrood CT coming into service and capital work carried over from 2014.
12	Interest	Interest costs have increased by $5.2 million from 2015 Test Year to the 2015 Forecast primarily due to an increase in RSP interest of $7.6 million, a decrease of $7.3 million in capitalized interest primarily due to postponement of LabWest capital project, and higher short term interest costs of $1.7 million related to delay in long term borrowing. These amounts are partially offset by interest savings of $10.8 million due to a delay in debt issue from April 1, 2015 to December 1, 2015.

Appendix B
Isolated Systems Supply Cost Variance Account - 2015 Forecast

Particulars	Diesel	HQ Purchases	Other [1]	Total
A - 2015 Forecast Supply Produced and Purchased (kWh)	52,945,609	23,973,640	650,140	77,569,389
B - 2015 Forecast Cost / 2015 Actual Production ($/kWh) [B1 / B2]	0.3073	0.1243	0.2667	0.2504
C - 2015 Test Year Cost / 2015 Test Year Production ($/kWh) [C1 / C2]	0.3259	0.1303	0.2941	0.2691
Isolated Supply Costs [A x (B-C)]				(1,454,872)
Cost Variance Threshold				(500,000)
Isolated Systems Supply Cost Deferral Balance				**(954,872)**
B1 - 2015 Forecast Cost of No. 2 Fuel + Purchases ($)	16,270,399	2,978,831	173,366	19,422,596
B2 - 2015 Forecast Production + 2015 Actual Purchases (kWh)	52,945,609	23,973,640	650,140	77,569,389
C1 - 2015 Test Year Cost of No. 2 Fuel + Purchases ($)	18,592,400	3,054,696	173,500	21,820,596
C2 - 2015 Test Year Production + 2015 Test Year Purchases (kWh)	57,048,141	23,435,400	590,000	81,073,541

[1] Other consists of purchases of Wind Generation at Ramea.

Appendix C
Energy Supply Cost Variance Deferral Account - 2015 Forecast

	Power Purchases					
Particulars ($)	**Wind**	**CBPP**	**Hydraulic [1]**	**Diesel**	**Gas Turbine**	**Total**
A - Forecast Energy Supply Costs	12,318,933	10,703,687	30,823,334	115,161	10,557,465	64,518,580
B - Test Year Energy Supply Costs	12,732,178	10,281,290	32,280,949	87,140	3,473,690	58,855,247
C - Energy Supply (Costs)/Savings [D/E x F]						(1,900,475)
Energy Supply Costs [(A-B)-C]						7,563,809
Cost Variance Threshold						500,000
Energy Supply Costs Deferral Balance						**7,063,809**
D - Holyrood 2015 Test Year Average Fuel Cost (bbl)						64.41
E - Test Year Fuel Conversion Factor (kWh/bbl)						607
F - Annual kWh variance - 2015 Forecast vs. 2015 Test Year (kWh) [F1-F2]						(17,910,079)
F1 - Forecast Consumption (kWh)						1,027,549,921
F2 - Test Year Consumption (kWh)						1,045,460,000

[1] Includes Nalcor Grand Falls, Bishop Falls and Buchans.

Appendix D
Holyrood Fuel Conversion Rate Deferral Account

Particulars	2015 Forecast	Effciency Factor (kWh/bbl)
A - Forecast quantity of No.6 fuel consumed (bbl)	2,284,246	597
B - Calculated quantity of No. 6 fuel consumed using the 2015 Test Year Cost of Service fuel conversion rate (bbl) [1]	2,246,707	607
C - 2015 Test Year Cost of Service No. 6 fuel cost ($) per bbl	64.41	
Holyrood Fuel Conversion Rate Costs Deferral Balance ($) [(A - B) x C]	2,417,870	

[1]Calculation of B:

D - Forecast net Holyrood production (kWh)	1,363,751,309	
E - 2015 Test Year Cost of Service fuel conversion rate (kWh/bbl)	607	

Appendix E
Change in Test Year Holyrood Fuel Conversion Rate

Particulars	**2015 Forecast**	**Effciency Factor (kWh/bbl)**
A - Forecast quantity of No.6 fuel consumed (bbl)	2,284,246	597
B - Calculated quantity of No. 6 fuel consumed using the 2007 Test Year Cost of Service fuel conversion rate (bbl) [1]	2,164,685	630
C - 2007 Test Year Cost of Service No. 6 fuel cost ($) per bbl	55.47	
Holyrood Fuel Conversion Rate Costs ($) [(A - B) x C]	6,632,070	
Less 2015 Test Year Calculation from Appendix D (607 kWh/bbl @ $64.41)	(2,417,870)	
Holyrood Fuel Conversion Test Year Differential	4,214,200	

[1]Calculation of B:

D - Forecast net Holyrood production (kWh)	1,363,751,309	
E - 2007 Test Year Cost of Service fuel conversion rate (kWh/bbl)	630	

Appendix F

2015 Cost Deferral Account

This account shall be charged with the variance of $60.5 million between forecast operating costs, amortizations and cost of capital for 2015, and forecast revenue for 2015. Disposition of the balance in this account will be subject to a further order of the Board.

IN THE MATTER OF the *Electrical Power Control Act, 1994,* SNL 1994, Chapter E-5.1 (the *"EPCA")* and the *Public Utilities Act,* RSNL 1990, Chapter P-47 (the *"Act"),* as amended, and regulations thereunder; and

IN THE MATTER OF a general rate application filed by Newfoundland and Labrador Hydro on July 30, 2013; and

IN THE MATTER OF an amended general rate application filed by Newfoundland and Labrador Hydro on November 10, 2014.

WHEREAS Newfoundland and Labrador Hydro ("Hydro" or the "Applicant") has applied to the Board of Commissioners of Public Utilities (the "Board") to establish customer electricity rates for 2015 and to recover a 2014 revenue deficiency (the "Application"); and

WHEREAS the Consumer Advocate; Newfoundland Power Inc. ("Newfoundland Power"); Corner Brook Pulp and Paper Limited, NARL Refining Limited Partnership and Teck Resources Limited (the "Industrial Customer Group"); Vale Newfoundland and Labrador Limited ("Vale"); the Innu Nation; the Towns of Labrador City, Wabush, Happy Valley-Goose Bay, and North West River; Yvonne Jones, MP and the Nunatsiavut Government have been granted Registered Intervenor status; and

WHEREAS the Applicant, the Consumer Advocate, Newfoundland Power, the Industrial Customer Group and Vale (the "Parties"), with participation by Board Hearing Counsel, have engaged in negotiations regarding Island Interconnected System and other issues.

Terms of Agreement

1. The Parties jointly advise the Board that certain issues arising from the Application have been settled by negotiations between them in accordance with this Settlement Agreement (the "Settled Issues").

2. The Parties recommend that the Board implement the agreement of the Parties regarding the Settled Issues in its Order.

3. The Parties consent to the admission in the record of this Application of all pre-filed testimony, exhibits and responses to requests for information pertaining to the Settled Issues. At the hearing of the Application, the Parties do not intend to present evidence, examine, cross-examine or present argument in relation to the Settled Issues beyond that which is reasonably necessary to assist the Board's understanding, and to explain or clarify the Parties' agreement concerning the Settled Issues, except insofar as may be necessary to

address issues that have not been settled by this Agreement and provided further that the Board includes the Settled Issues in its Order.

4. This Settlement Agreement represents a reasoned consensus on the Settled Issues and the agreements on individual issues are not intended to be severable.

5. This Settlement Agreement does not dispose of all issues arising from the Application. It does not limit the rights of the Parties to present evidence, examine, cross-examine and present argument at the hearing of the Application on issues that have not been settled by this Agreement.

6. This Settlement Agreement is without prejudice to the positions the Parties may take in proceedings other than the Application. Its sets no precedent for any issue addressed in this Settlement Agreement in any future proceeding or forum.

Matters Agreed Upon

Range of Return

7. The Parties agree that the allowable range of return on rate base for Hydro will be +/- 20 basis points.

Revenue Requirement

8. The Parties agree that Hydro's proposed accounting treatment to include actuarial gains and losses in Employee Future Benefits in the 2015 Test Year should be approved.

9. The Parties agree that Hydro's proposal to include depreciation and accretion expenses associated with Asset Retirement Obligations should be approved with the amounts reduced from \$3.1 million and \$3.2 million for the 2014 and 2015 Test Years, respectively, as proposed in the Application to \$2.6 million and \$2.6 million, respectively. The reduction from the amounts proposed in the Application reflects amounts excluded for construction and selective decommissioning costs at the Holyrood generating plant as these costs will be incurred to the benefit of customers subsequent to the Labrador-Island Interconnection and Hydro may apply for recovery of such costs in future applications.

10. The Parties agree that the methodology used by Hydro to estimate its average annual hydroelectric energy productions should be approved and the 2015 hydraulic production calculation forecast of 4,604 GWh should be approved for all purposes, including the calculation of No. 6 fuel expense for the 2015 Test Year and for the Rate Stabilization Plan.

11. The Parties agree that Hydro's proposed depreciation methodology used to determine depreciation expense in the 2015 Test Year is appropriate.

Cost of Service

12. The Parties agree that Hydro's cost of service study filed in this proceeding is in general compliance with Board Orders regarding the use of embedded cost of service studies as a guide in determining the revenue requirement to be applied to each customer class.

13. The Parties agree on the cost of service methodologies in Exhibit 13 (2015 Test Year Cost of Service) with respect to Functionalization, Classification and Allocation, with the exception of:
    (a) the treatment of the curtailable load of Newfoundland Power;
    (b) the classification of wind energy purchases as 100% energy related;
    (c) the calculation of the capacity factor for the Holyrood Generating Plant;
    (d) the classification of all Holyrood fuel costs to energy;
    (e) Newfoundland Power's load factor;
    (f) the use of the forecast 2015 load for rate-setting purposes;
    (g) the basis on which specifically assigned charges to customers is calculated;
    (h) the specific assignment of the frequency converter to Corner Brook Pulp and Paper Limited, the calculation of that charge and any credit in the cost of service study associated with the frequency converter; and
    (i) the allocation methodology for the Rural Deficit.

14. The Parties agree, notwithstanding the generality of the principle agreed to in paragraph 13 of this Settlement Agreement, on the following specific elements of Hydro's 2015 Cost of Service:
    (a) the Utility Rate shall include a generation credit for Newfoundland Power of 119,329 kW applied in the same manner as in the last approved 2007 cost of service study to reduce Newfoundland Power's peak demand for cost allocation purposes; and
    (b) the costs associated with Hydro's capacity assistance agreements with Vale and Corner Brook Pulp and Paper Limited shall be treated as demand related.

Rate Design

15. The Parties agree that the current rate design for industrial customers should continue to apply as Hydro proposed in the Application.

Rate Stabilization Plan

16. The Parties agree that, if load variation is maintained as an element of the Rate Stabilization Plan, year-to-date net load variations for Newfoundland Power and industrial customers shall be allocated among the customer groups based upon energy ratios, with effect from the date to be determined by the Board.

Regulatory Deferral and Recovery Mechanisms

17. The Parties agree that Hydro's proposal to defer and amortize annual customer energy conservation program costs, commencing in 2015, over a discrete seven year period in a Conservation and Demand Management (CDM) Cost Deferral Account should be approved.

18. The Parties agree that the Board should approve that costs related to the Application be recovered in customer rates evenly over a three year period, commencing with the date that new rates approved in this proceeding become effective with the amount of such costs to be determined by the Board.

Agreement with Corner Brook Pulp and Paper Limited

19. The Parties agree that the generation credit agreement between Hydro and Corner Brook Pulp and Paper Limited which was approved on a pilot basis by the Board in Order No. P.U. 4(2012) should be continued on a pilot basis at this time and that it will be reviewed in the cost of service generic hearing referred to in paragraph 23 of this Settlement Agreement.

Wheeling Rate

20. The Parties agree that upon finalization of the 2015 Test Year by the Board there shall be an industrial wheeling rate with the specific rate to be calculated in accordance with the methodology proposed by Hydro in its Application as may be modified by the Board in an Order arising from the Application.

Customer Service Strategy

21. The Parties agree that the Customer Service Strategic Roadmap 2015-2017 filed by Hydro in this proceeding reflects appropriate customer service improvement objectives, but this does not preclude additional customer service improvements being raised during the hearing of this Application or being considered by the Board .

Reporting on Key Performance Indicators

22. The Parties agree that Hydro should continue to report functionally oriented key performance indicators as required by the Board in Order No. P.U. 14(2014), however, such reporting will be based on the most recent Test Year Cost of Service Study that is approved by the Board and not on a forecast basis.

Future Reports and Applications

23. Hydro has stated in this proceeding that in preparation for the implementation of customer rates reflecting the costs of the Labrador-Island interconnection, it will file with the Board the following:

(a) a marginal cost study no later than December 31, 2015;
(b) a cost of service methodology report no later than March 31, 2016;
(c) a report on the Rate Stabilization Plan and supply cost recovery mechanisms no later than June 15, 2016; and
(d) a General Rate Application no later than March 31, 2017 for rate changes based on a 2018 test year.

The Parties agree that the Board should in its Order direct Hydro to file these reports, studies and applications by the relevant dates set out in this paragraph. The Parties further agree that a generic cost of service hearing should be held following the filing of the reports outlined in (a) to (c) above.

24. Notwithstanding the requirements of paragraph 23 of this Settlement Agreement, the Parties agree that the Board in its Order should direct Hydro to file a General Rate Application on or before March 30, 2017 proposing rates based on a 2018 test year.

Remaining Issues

25. The Parties agree that issues not included in this Settlement Agreement remain unresolved and will be the subject of viva voce evidence at the hearing of the Application.

Agreed to as of the 14th day of August, 2015.

For Newfoundland and Labrador Hydro: ____________________

For the Consumer Advocate: ____________________

For Newfoundland Power Inc.: ____________________

For the Industrial Customer Group: ____________________

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For Vale: ____________________

For Board Hearing Counsel: Maureen Greene

A REPORT TO
THE BOARD OF COMMISSIONERS OF PUBLIC UTILITIES

2015 CONSERVATION COST DEFERRAL AND PROGRAM EXPANSION REPORT

Newfoundland and Labrador

November 12, 2015

newfoundland labrador hydro
a nalcor energy company

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1.0 Introduction

Newfoundland and Labrador Hydro (Hydro) has applied for approval from the Board of Commissioners of Public Utilities (the Board) for the deferral of the costs to be incurred by Hydro that are associated with the 2015 implementation of the Conservation and Demand Management (CDM) Programs and approach as outlined in the Five-Year Energy Conservation Plan: 2012-2016.[1] The purpose of this report is to provide the details of the 2015 CDM Program costs and an update of activities undertaken in 2015. The report also provides an overview of the conservation program planning activities completed during 2015 and included in a new Five-Year Conservation Plan: 2016-2020.[2]

The 2012-2016 Plan outlined the joint utility approach undertaken in partnership with Newfoundland Power. This report describes the provincial approach but focuses on the costs and reach of initiatives for Hydro's portion of program implementation that are addressed by the deferral request.

Hydro is requesting a deferral of an estimated $1,213,000 to be incurred in 2015, which was not included in Hydro's 2007 Test Year approved expenses for rates set by Board Order No. P.U. 8(2007).

2.0 Background

Energy Conservation initiatives was a topic of discussion during Hydro's 2006 General Rate Application (GRA). Since that time, Marbek Resource Consultants Limited (Marbek) was commissioned and completed a CDM Potential study in 2008 that provided information to assist in identifying cost-effective conservation programs and the potential contribution of specific technologies and measures in reducing forecast electricity consumption. From the potential study a five-year energy conservation plan was completed which outlined proposed energy conservation initiatives to be implemented jointly by Newfoundland Power

[1] The Five-Year Energy Conservation Plan: 2012-2016 was filed with the Board on September 14, 2012 as part of Newfoundland Power's General Rate Application.
[2] The Five-Year Conservation Plan: 2016-2020 was filed with the Board on October 16, 2015 as part of Newfoundland Power's 2016/2017 General Rate Application.

and Hydro (the Utilities), including technologies, programs, support elements and cost estimates that promote a long-term goal of an established conservation culture with sustained reductions in electricity consumption. The potential study was filed with the Board on March 20, 2008 and the 2008-2012 Plan was filed with the Board on June 27, 2008.

In September 2012, the Five-Year Energy Conservation Plan: 2012-2016 was filed with the Board. This updated Plan outlined additional programs to be launched to complement the existing portfolio of programs. The focus for joint utility conservation continues to be energy savings through the development of a culture of conservation. The activities in the 2012-2016 Plan include rebate programs for each sector (residential, commercial and industrial) and supporting activities for awareness, education and community engagement to stimulate attitude change.

An application to defer the recovery of 2009 costs to be incurred by Hydro in association with the implementation of the Energy Conservation Program was filed on November 21, 2008. This filing addressed forecasted costs for delivering the programs to Hydro customers in 2009. The Board approved the application in Order No. P.U. 14(2009).

An application to defer the recovery of 2010 costs estimated at $2.3 million to be incurred by Hydro in association with the implementation of the Energy Conservation Program was filed on January 26, 2010. This filing addressed forecasted costs for delivering the programs to Hydro customers in 2010. The Board approved the application in Order No. P.U. 13(2010).

An application to defer the recovery of 2011 costs estimated at $840,000 to be incurred by Hydro in association with the implementation of the Energy Conservation Program was filed on March 10, 2011. This filing addressed forecasted costs for delivering the programs to Hydro customers in 2011. The Board approved the application in Order No. P.U. 4(2011).

An application to defer the recovery of 2012 costs estimated at $1,673,000 to be incurred by Hydro in association with the implementation of the Energy Conservation Program was filed on December 22, 2011. This filing addressed forecasted costs for delivering the programs to Hydro customers in 2012. The Board approved the application in Order No. P.U. 3(2012).

An application to defer the recovery of 2013 costs estimated at $1,950,000 to be incurred by Hydro in association with the implementation of the Energy Conservation Program was filed on November 1, 2013. This filing addressed forecasted costs for delivering the programs to Hydro customers in 2013. The Board approved the application in Order No. P.U. 35(2013).

An application to defer the recovery of 2014 costs estimated at $2,520,000 to be incurred by Hydro in association with the implementation of the Energy Conservation Program was filed on September 30, 2014. This filing addressed forecasted costs for delivering the programs to Hydro customers in 2014. The Board approved the application in Order No. P.U. 43(2014).

Hydro is forecasting $1,213,000 to be accumulated in the deferral account associated with its energy conservation program activities for the 12-month period of January 2015 to December 2015.

3.0 Five-Year Plan Update

2015 has been an active and successful year with respect to Hydro's conservation and planning efforts. Significant energy savings are expected to be achieved within the residential and commercial energy efficiency program activities, particularly in the business efficiency, isolated community, and small technology (instant rebate) programs. Hydro continues to engage with its industrial customers concerning energy conservation improvements but no energy savings projects are forecast for this year. The ENERGY STAR® Window Program concluded at the end of 2014 having achieved its objective of making more efficient windows the standard in the local market. All program profiles are included with Appendix A.

Beginning in January 2015 the Utilities contracted with ICF International to undertake a conservation and demand management potential study to identify the achievable, cost-effective electric energy efficiency and demand management potential in the Province. The study was completed in 2015 and included consultation with customers, trade allies, retail partners, and other interested parties. A copy of the Newfoundland and Labrador Conservation and Demand Management Potential Study: 2015 for each of the Residential, Commercial, and Industrial Sectors was filed with the Board on September 15, 2015.

The Conservation and Demand Management Potential Study: 2015 was used by the Utilities to develop the Five-Year Conservation Plan: 2016-2020. A copy of the Five-Year Conservation Plan: 2016-2020 is included with Appendix B. This plan includes a new residential benchmarking program; expansion of existing commercial programs; and reshaping or discontinuation of elements of the residential program offerings. Hydro is also assessing implementation of a direct load control pilot for the community of Postville, Labrador with aim to reduce peak loading and defer system expansion. Hydro is presently managing a home energy monitoring project on behalf of the Provincial Office of Climate Change and Energy Efficiency, which will be completed in 2016. The results of this project will be used to assess whether real time monitoring of home energy may be considered for future conservation initiatives.

4.0 Program Portfolio

The existing Energy Savers Rebate programs offered through the takeCHARGE program launched in June 2009 continued to be offered in 2015. These programs have shown energy savings and continue to encourage consumers to consider energy efficiency in their purchasing decisions. The programs target the highest end uses for the residential and commercial markets of heating and lighting, respectively. These programs are:

- Residential Thermostats;
- Residential Insulation; and
- Commercial Lighting.

The custom Industrial Energy Efficiency Program (IEEP) was also available to transmission level Industrial Customers if they wished to participate, however 2015 mainly involves engagement with industrial facility managers to promote and seek future energy efficiency projects. No energy savings were forecast for the industrial sector in 2015.

The Energy Savers Rebate Programs are offered provincially, however the costs associated with delivery in the Labrador Interconnected System are recorded separately than those for the Island Interconnected and the Isolated Diesel systems. Outside the Labrador Interconnected System, the dominant economic driver is the avoided fuel cost. In the Labrador Interconnected System the dominant economic driver is export market sales. To ensure the costs of conservation are associated with those who receive the primary benefits, the costs of conservation and efficiency on the Labrador Interconnected System are considered non-regulated.

In addition to the existing Energy Savers programs, there are two programs currently being delivered in Hydro’s service area. The Isolated Systems Community Program and Isolated Systems Business Efficiency Program were launched in June 2012 and provide rebates, information and technical support to home and business owners in isolated communities.

The following tables show Hydro’s total CDM expenses and energy savings from 2009 to 2015 across all of Hydro’s systems, including the Labrador Interconnected System. This report will provide further detail and breakdown of the costs that will be recovered through the deferral account and the associated energy reductions. The energy conservation programs are assessed economically using current standard utility economic screening tests[3]. All program descriptions and profiles are provided in Appendix A.

[3] The primary test for economic viability is the Total Resource Cost (TRC) test which includes both the participants’ and Utility’s costs and benefits as factors in the net value of the program. As outlined in the Plan, each program has a positive TRC, which means the total program benefits exceed the total costs of the program.

Table 1: Hydro CDM Portfolio Spending ($000s)

	2009	2010	2011	2012	2013	2014	2015(F)
Windows	44	49	80	117	169	38	8
Insulation	40	61	140	126	157	92	98
Thermostats	13	19	31	47	51	35	37
Coupon Program	-	135	135	-	-	-	-
Commercial Lighting	12	12	59	20	29	15	65
Industrial	57	226	103	173	89	1,244	5
Block Heater Timer				31	8	8	-
Isolated Community				858	871	615	550
ISBEP				93	115	96	68
Heat Recovery Ventilator				-	11	7	57
Business Efficiency Program				-	45	101	90
Small Technologies				-	1	252	329
Total Portfolio	**166**	**502**	**548**	**1,465**	**1,546**	**2,503**	**1,307**

Table 2: Hydro's Annual CDM Portfolio Energy Savings (MWh)

	2009	2010	2011	2012	2013	2014	2015 (F)
Windows	13	37	61	136	99	85	0
Insulation	35	126	404	382	794	142	76
Thermostats	9	35	30	53	24	38	8
Coupon Program	-	64	256	-	-	-	
Commercial Lighting	3	10	227	95	99	79	52
Industrial	-	-	165	3,172	-	22,258	
Block Heater Timer				-	288	-	
Isolated Community				1,676	1,096	1,357	650
ISBEP				3	27	111	232
HE HRV					1	6	6
Business Efficiency Program					-	107	500
Small Technologies					-	148	81
Total	**60**	**272**	**1,143**	**5,517**	**2,428**	**24,331**	**1,605**

4.1 takeCHARGE Approach

The takeCHARGE approach was described in detail in Hydro's 2010 Conservation Cost deferral report submitted in January 2011. The joint utility effort allows for economies of scale to be achieved where possible in areas such as marketing and outreach efforts. The technologies selected for rebate programs address large energy use opportunities and have been verified as cost effective through standard utility economic screening. In addition, a range of education efforts around general energy efficiency messaging have also been implemented to develop a culture of conservation.

The utilities continue to receive positive response to the existing programs that address a wide provincial customer base. However, there have been opportunities identified that address different needs within each utilities' customer base. For example, Hydro's rural customers respond positively to community engagement efforts as demonstrated by the Isolated Systems Community Program, which includes hiring and training local community representatives to communicate directly with customers through home visits and direct installation of energy efficient measures. The Utilities continue to work together to create and improve provincial scope programs, but also seek projects and programs that can be of benefit if implemented in a system-targeted program.

Technology selection continues to follow the same process of focusing on the significant end uses and identifying niche opportunities where the market can be moved to a more efficient choice. For example, residential home heating is a large end use but the technology portfolio also includes a range of savings options for customers to reduce their electricity consumption across more end uses. This is reflected in the small technology (Instant Rebates) program that provides incentives to homeowners for smaller technologies such as lighting options, timers, and water conservation, as well as rebates for appliance and electronics, opening new ways to save energy.

The utilities will continue to use traditional methods of advertising and promotion, participate in community events, work with community leaders and utilize social media opportunities. This holistic approach to addressing technology, the end user and the community is an effective option for fostering sustainable behaviour and attitude change.

4.2 Program Highlights and Next Steps

Participation continues to increase through Hydro's service area. Retailers continue to be key partners in reaching customers, and a pilot project undertaken in 2011-2012 with retailers to promote ENERGY STAR Window purchases and rebate submission demonstrated this role. Hydro continued to partner and work with retailers in 2015 for the Small Technologies program that enables customers to receive point-of-sale rebates on a number of energy efficient products. Building relationships with retailers will continue to be a focus as part of the energy efficiency promotion.

Outreach and non-traditional promotions and awareness building have also shown to have impact in reaching Hydro's diverse market. For example, the takeCHARGE program has been represented through community events, product exchanges and giveaways to reach customers in a variety of ways. The direct install approach involves training and using local representatives in isolated communities to provide technologies to homeowners and businesses as well as the free installation of the technologies. This program clearly shows the value of community engagement and creating an interest around the program at community launch events.

Much of Hydro's customer base for high performance commercial lighting consists of government facilities and we continue to work with government departments to identify lighting improvement opportunities when facility renovations and construction are planned. Hydro also continues to work with lighting distributors to promote sale and installation of high performance lighting products.

In the summer of 2011, the Isolated Systems Business Efficiency Program (ISBEP) was launched, providing rebates and technical assistance for commercial customers in isolated diesel communities. This custom approach is similar to the Business Efficiency (BEP) and Industrial Energy Efficiency (IEEP) programs where Hydro technical staff work with customers one-on-one to address their energy efficiency needs. The business efficiency programs have seen steady activity and commercial customers have been engaged in the Central, Northern, and Labrador Regions that identified several projects for 2015. Hydro continues to work with its commercial and Industrial Customers to identify opportunities that produce energy and operational savings.

The utilities initiated a new CDM Potential Study in late 2014 with a final report completed in 2015. Hydro continues to work with Newfoundland Power and other partners to determine emerging opportunities for CDM programming and develop appropriate strategies for developing a conservation culture in the province.

5.0 Program and Support Costs

The energy savings from Hydro customers in relation to programming associated with the annual CDM deferral requests to date and forecast in 2015 are shown in Table 3. It should be noted that while there are costs associated with the Small Technologies program in 2013 there are no associated savings. This is because the program detailed design stage began in 2013, and the program was launched 2014.

Table 3: Annual Energy Savings from Deferral Account Activity (MWh)

	2009	2010	2011	2012	2013	2014	2015 (F)
Windows	8	14	38	50	43	40	0
Insulation	29	63	229	126	123	100	26
Thermostats	2	16	16	28	14	16	4
Coupon Program	-	47	166	-	-	-	
Commercial Lighting	3	-	92	25	19	22	16
Industrial	-	-	165	3,172	-	22,258	
Block Heater Timer				-	-	-	
Isolated Community				1,676	1,096	1,357	650
ISBEP				3	27	111	232
Heat Recovery Ventilator				-	-	1	2
Business Efficiency Program				-	-	73	500
Small Technologies				-	-	80	44
Total	**42**	**140**	**706**	**5,080**	**1,322**	**24,058**	**1,474**

In 2015 the Commercial Lighting program continued to be offered solely through the distributors and as such there is little to no direct customer contact for promotions and information, so this program remains somewhat unpredictable for savings estimates. The Block Heater Timer program was offered in the Labrador Interconnected area from 2012 to 2014, therefore no savings are associated with the deferral account.

Program costs associated with this deferral[4] request for 2015 are shown in Table 4.

[4] Proposed definition of the deferral account was submitted to the Board on April 22, 2009.

Table 4: Program Costs from Deferral Account Activity ($000s)

	2009	2010	2011	2012	2013	2014	2015(F)
Windows	44	41	69	102	150	31	8
Insulation	40	53	116	108	112	87	89
Thermostats	13	18	25	43	47	32	34
Coupon Program	-	113	123	-	-	-	
Commercial Lighting	13	-	43	10	17	10	59
Industrial	57	190	98	170	88	1,244	5
Block Heater Timer				-	-	-	
Isolated Community				858	871	615	550
ISBEP				93	115	96	68
Heat Recovery Ventilator				-	8	3	44
Business Efficiency Program				-	40	92	68
Small Technologies				-	1	219	289
Total Portfolio	**167**	**415**	**474**	**1,384**	**1,449**	**2,429**	**1,213**

The costs associated with the delivery of the CDM program portfolio include direct costs for advertising, salaries, rebates and other expenses directly associated with a specific rebate program. These costs vary depending on the uptake of the program and the number of programs offered.

There are two components of the costs associated with the conservation and efficiency function. In addition to direct program costs which are charged to the deferral account, there are costs associated with general energy efficiency awareness and education, strategic planning and program development. These costs remain relatively stable regardless of the number of rebate programs currently offered in the portfolio.

Hydro's support costs are outlined in Table 5 below. While these costs were in line with expectations for education and support, there was an increase in planning costs as a result of consultant support for the 2015 CDM Potential Study, and Hydro's contributions to the Potential Study, and development of the Five-Year Conservation Plan: 2016-2020.

Table 5: Hydro's Support Costs ($000s)							
	2009	**2010**	**2011**	**2012**	**2013**	**2014**	**2015(F)**
Education	262	106	212	200	135	158	156
Support	53	48	43	53	27	52	65
Planning	176	180	304	127	152	224	434
Total	**491**	**334**	**559**	**380**	**314**	**434**	**655**

6.0 Justification

Hydro is seeking approval to defer the CDM program costs it will incur in 2015 and for the recovery of these amounts in a manner to be determined by the Board in Hydro's Amended General Rate Application (2013), filed November 10, 2014. Hydro's total annual program costs in 2015 to be deferred are forecast to be $1,213,000. These costs were not forecast in Hydro's 2007 Test Year to be recovered in rates as set by Board Order No. P.U. 8(2007). Hydro is not seeking approval to defer non-program costs for 2015, estimated to be $655,000.

If the 2015 CDM program costs are not deferred they must be recognized as expenses incurred in 2015. This will have significant impact on Hydro's income in that year. The CDM costs incurred provide ongoing system benefits through energy reductions and associated fuel savings. The appropriate regulatory treatment of these costs is included in Hydro's Amended General Rate Application (2013), filed November 10, 2014.

7.0 Conclusion

Hydro has estimated that it will incur $1,213,000 in CDM Program expenses in 2015 associated with the Deferral Account. These expenses are in excess of Hydro's forecast costs used to set rates by Board Order P.U. 8(2007). Therefore, Hydro is requesting approval from the Board for the deferral of the costs to be incurred by Hydro that are associated with the implementation of the joint utility CDM approach as outlined in the Plan and further described in this report.

Appendix A:

NLH Program Profiles

Insulation Program

Program Description

The objective of this program is to increase the insulation level in residential basements, crawl spaces and attics. Increasing the insulation R-value in a home will result in space heating energy savings. The program components include rebates and financing, and a variety of education and marketing tools. This program has been offered through takeCHARGE since 2009.

Target Market: Residential

This program targets residential customers. Changes to the National Building Code of Canada mandates that all new homes install basement insulation. As a result, this program was modified in 2013 to exclude minimum building code compliance in new homes. Eligibility will continue to be limited to electrically-heated homes.

Eligible Measures

Eligible measures in this program include insulation upgrades to basements, crawl spaces and attics. Technical requirements will be aligned with National Building Code of Canada.

Delivery Strategy

The delivery strategy for this program remains unchanged. Delivery of this program will continue to be bundled with the *ENERGY STAR* window, thermostat and HRV programs as part of the takeCHARGE residential portfolio.

Marketing initiatives include partnering with retailers and trade allies in the home building and renovation industry, and target both do-it-yourself and professional installers. Tools and tactics will include retail and model home point-of-sale materials, advertising, website, tradeshows, community outreach and trade ally activities. Rebates and financing will be processed through customer application.

Insulation Program

Market Considerations
Barriers to increased market penetration include initial cost, awareness of the impact on space heating energy, and the practical difficulties of renovating an existing living space. Experience with the existing program has shown participation to be responsive to awareness-building marketing activities. With the implementation of the new building standards, market penetration of basement insulation in new homes is expected to increase.
Incentive Strategy
Incentives for this program include rebates. The rebate amount changed in 2014 to 75% of the cost for basement insulation and 50% of the cost for attic insulation up to $1,000.
Program Monitoring & Evaluation
The program will be monitored for participation level, service quality, and cost effectiveness and a representative sample of installations will be inspected. Formal evaluations will be conducted every two years during operation.
Estimated Costs & Energy Savings
2015 Hydro Estimated: Deferral Cost - $89,000 Associated Savings – 26 MWh/yr

Thermostat Program

Program Description

The objective of this program is to encourage installation of programmable and high performance electronic thermostats in homes. Programmable and high performance electronic thermostats allow customers to better control the temperature of their homes and to set back the temperature during the night or while away. The program components consist of rebates, financing options, and a variety of education and marketing tools. This program has been offered through takeCHARGE since 2009.

Target Market: Residential

This program targets residential customers, including home retrofit and new home construction. Eligibility will continue to be limited to electrically-heated homes.

Eligible Measures

Eligible measures in this program include both programmable and high performance electronic thermostats (those which control within +/- 0.5^{o}C.)

Delivery Strategy

The delivery strategy for this program remains unchanged. Delivery of this program will continue to be bundled with the insulation, windows and Heat Recovery Ventilation (HRV) programs as part of the takeCHARGE residential portfolio.

Marketing initiatives include partnering with retailers, electrical contractors, homebuilders and real estate professionals, to educate consumers regarding the energy savings and comfort benefits of programmable and high performance thermostats. Tools and tactics include retail and model home point-of-sale materials, website, tradeshows, community outreach and trade ally activities. Rebates will be processed through customer-submitted coupons.

Thermostat Program

Market Considerations

Market penetration of programmable and high performance electronic thermostats has increased in the past two years, but continues to represent a small portion of the overall sales volume. Minimum quality thermostats continue to be widely used in new home construction. The St. John's Energy Reduction Strategy that was implemented in September 2011 requires all new homes in the city to have electronic thermostats installed. This is expected to create increased participation in the program for customers residing in the city and may have some spillover effects. Thermostat requirements are not expected to be affected by National Building Code changes.

Incentive Strategy

Incentives for this program include rebates and financing. The rebate value is $5 per electronic thermostat and $10 per programmable thermostat. This continues to reflect incremental cost of the more efficient options. A time limit will be implemented for incentive redemption.

Program Monitoring & Evaluation

The program will be monitored for participation level, service quality, and cost effectiveness, and a representative sample of installations will be inspected. Formal evaluations will be conducted every two years during program operation.

Estimated Costs & Energy Savings

2015 Hydro Estimated:

Deferral Cost - $4,000

Associated Savings – 34 MWh/yr

ENERGY STAR Window Program

Program Description

The objective of this program was to increase the installation of *ENERGY STAR* windows instead of standard windows. *ENERGY STAR* windows improve the efficiency of the home's building envelope and provide savings in space heating energy. The program components consisted of rebates, financing options, and a variety of education and marketing tools. This program was offered through takeCHARGE from 2009 to 2014.

Target Market: Residential

Until December 31, 2014 this program targeted new and existing residential home owners to install more energy efficient windows. Eligibility was limited to electrically-heated homes. This program was closed at the end of 2014 as result of the market having transformed to ENERGY STAR windows as the standard.

Eligible Measures

Eligible measures in this program are *ENERGY STAR* qualified windows.

Delivery Strategy

The delivery strategy for this program remained unchanged to December 31, 2014 when it ended. Delivery of the program was bundled with the insulation, thermostat and HRV programs as part of the takeCHARGE residential portfolio.

Marketing initiatives included partnering with retailers and trade allies in the home building and renovation industry, and targeted both do-it-yourself and professional installers. Communications incorporated the *ENERGY STAR* brand and related marketing support. Tools and tactics included retail and model home point-of-sale materials, advertising, website, tradeshows, community outreach and trade ally activities. Rebates and financing will be processed primarily through customer application.

ENERGY STAR Window Program

Market Considerations

ENERGY STAR qualified windows currently comprise approximately 50% - 60% of window sales in the province, compared to 10% - 15% in 2008. With the implementation of National Building Code changes in 2013, market penetration is expected to increase in new homes. Understanding of the product is improving among customers and retailers. Eligible windows are widely available.

Incentive Strategy

Incentives for this program included rebates and financing. A rebate of $2 per square foot of window installed was offered.

Program Monitoring & Evaluation

The program was monitored for participation level, service quality, and cost effectiveness, market penetration and a representative sample of installations were inspected.

Estimated Costs & Energy Savings

2015 Hydro Estimated:

Deferral Cost - $8,000 – this was residual rebate applications from late 2014 processes early 2015.

Associated Savings – N/A

Isolated Systems Community Program

Program Description

The objective of this program is to provide a portfolio of technologies and opportunities to save energy that will move the residential and commercial isolated system customers along an energy efficiency continuum.

Target Market

This program targets both residential and commercial customers in Hydro's isolated systems. This includes Isolated Diesel systems on the Island and in Labrador and the L'Anse au Loup system. Eligibility for specific components of the program will be determined on a per customer basis and may be limited by primary heating source.

Eligible Measures

Measures will be wide ranging, from smaller items such as CFLs, showerheads and hot water pipe insulation, to high efficiency appliances, and cross promotions for the existing takeCHARGE Energy Savers Rebate programs.

Delivery Strategy

Hydro has engaged Summerhill Group to deliver this program, using a number of delivery strategies to engage residential and commercial customers. These include direct install efforts, whereby the customer receives the technology in their home or business at no cost. During the direct install visit, customers also receive information on energy usage and efficiency options. Mail-in rebates are provided for eligible purchases, such as appliances. Local retailers are engaged to provide additional coupons and price reductions on other products as well as exchange events for products such as LED holiday lighting. The existing takeCHARGE programs are being promoted to increase participation in those programs within the isolated systems.

Isolated Systems Community Program

Market Considerations

Availability and awareness of energy efficient technologies continues to be an issue in rural communities and often technologies available are at a higher price than in urban markets. This program will address the barriers of availability and as the avoided costs in isolated markets are higher than the Island Interconnected system, programming can be more aggressive. The customer base has been primarily non-electric heat, but electric heat load has been growing. There is a heavy electric hot water heating penetration and opportunities exist in plug load and behavior based areas.

Commercial customers tend to be smaller businesses and as such find it challenging to find the time and resources to address energy consumption issues and this program will provide the one on one interaction needed to assist these customers.

Incentive Strategy

The technologies used in the direct install component of the program will be installed at no cost to participating homes and businesses. Additional incentives will be dependent on the technology and the resulting savings.

Program Monitoring & Evaluation

The program will be monitored for participation level, service quality, and cost effectiveness, and a representative sample of direct installs will be surveyed for confirmation of continued installation and use.

Estimated Costs & Energy Savings

2015 Hydro Estimated:

Deferral Cost - $550,000

Associated Savings -650 MWh/yr

Small Technologies Program

Program Description

The objective of this program is to increase the efficiency levels in homes and increase energy efficiency awareness by offering instant rebate coupons on a list of energy efficient technologies. There will also be promotional events to raise awareness of the technologies and to engage the public.

Target Market: Residential

The small technology program will be marketed toward residential customers province wide. All customers will be eligible to participate regardless of age of home or heat source.

Eligible Measures

Eligible measures in this program will vary over time and will be selected based on cost effectiveness, energy saving potential and market conditions.

Delivery Strategy

Partnerships will be made with both chain and independent retailers to offer instant rebates to customers on a number of energy efficient products. The intent is to update the list each year, encouraging customers to purchase more products over time.

Coupon campaigns will be offered each year. These campaigns will include the delivery of public engagement events held at retailers. These events will consist of exchanges and giveaways that will promote the technologies offered through the coupons.

Small Technologies Program

Market Considerations

The technologies included in the program do not involve a major renovation. This program will allow the Utilities to reach customers that may not have been able to participate in the other incentive programs.

Incentive Strategy

Incentives for this program include instant rebates that will vary by year and campaign. The rebate value will be different for each technology offered, and will reflect incremental cost of the more efficient options.

Program Monitoring & Evaluation

The program will be monitored for participation level, service quality, and cost effectiveness. Exit interviews will be conducted during selected retail events. Formal evaluations will be conducted after the first year of implementation, and biannually during operation.

Estimated Costs & Energy Savings

2015 Hydro Estimated:

Deferral Cost - $289,000

Associated Savings -44 MWh/yr

HE HRV Program

Program Description

The objective of this program is to increase the installation of higher efficiency HRVs (those with a sensible heat recovery efficiency, or SRE, level of 70% or more). In 2013, the National Building Code is expected to require all new home HRV installations to have an SRE level of at least 60%. The program components include rebates and financing, and a variety of education and marketing tools.

Target Market: Residential

This program targets all residential customers regardless of heat source or age of home. Eligibility is available to all homes that install or replace an HRV.

Eligible Measures

Eligible measures in this program include all HRV models that have an SRE of 70% or more.

Delivery Strategy

Delivery of this program will be bundled with the insulation, window and thermostat programs as part of the takeCHARGE residential portfolio.

Marketing initiatives include partnering with retailers and trade allies in the home building and renovation industry, particularly certified HRV installers. Tools and tactics will include retail and model home point-of-sale materials, advertising, website, tradeshows, community outreach and trade ally activities. Rebates and financing will be processed through customer application.

HE HRV Program

Market Considerations
The market includes new construction and existing HRV replacement. HRVs are widely used in new home construction in the province. Early HRV installations of the 1990s are at or near the end of their useful life, so many of these will require replacement in the planning period. Initial cost is a barrier to increased market penetration, as is awareness of the benefits of selecting more efficient HRVs.
Incentive Strategy
Incentives for this program include rebates and financing. The rebate value is estimated to be $175 for qualifying HRV units. This will reflect incremental cost of the more efficient options.
Program Monitoring & Evaluation
The program will be monitored for participation level, service quality, and cost effectiveness and a representative sample of installations will be inspected. Formal evaluations will be conducted after the first year of implementation, and every two years during operation.
Estimated Costs & Energy Savings
2015 Hydro Estimated: Deferral Cost - $44,000 Associated Savings -2 MWh/yr

Block Heater Timers Program

Program Description

This program encourages the use of block heater timers by residential vehicle owners in the Labrador West and Central regions. Vehicle owners regularly plug in their block heaters overnight but three hours is enough for the safe operation of the vehicle to warm the coolant and the engine. The timers are available through giveaway and incented through at cash retail coupons.

Target Market: Residential

The program targets residential vehicle owners in the Labrador West and Central regions that do not currently use timers for their block heaters. It is estimated there is a potential market of nearly 10,000 residential vehicles in the region.

Eligible Measures

Eligible timers are 120 volt heavy duty outdoor timers with either manual or digital programming options. Timers provided through Hydro's giveaways are pre-programmed for a three hour operation whereas those available at retailers may be pre-programmed or require set up.

Delivery Strategy

The Block Heater Timer Program will run during the winter months with active promotions and giveaways to highlight the technology. The program will be launched with giveaway events happening at partner retailers in both Labrador West and Central and follow with the introduction of the $10 at cash rebate on pre-approved models of timers. Marketing and promotions include print and radio and efforts are made to engage local employers and find champions to be advocates of the product.

The launch event giveaway provides a limited number of pre-programmed timers to customers. These customers are required to participate in survey research to determine their attitudes towards and use of the timers for future verification of savings and to adjust marketing and promotional efforts.

Hydro will also explore partnerships with other groups and businesses in the region regarding further promotions and awareness of the product.

Block Heater Timers Program

Market Considerations
Initial research indicates that while block heaters are used extensively, timers are rarely used. It is common perception that a block heaters need to be plugged in overnight, rather than for limited time before start up. As well, due to lack of demand, retailers do not regularly carry the product and efforts need to be made with partner retailers to ensure on-going access to the timers. The average retail price for an eligible timer is approximately $23. Promotions and delivery strategies address both the customer perception and retail access components.
Incentive Strategy
The program provides giveaway of the technology initially to create awareness of the product and a $10 at cash rebate is provided through partner retailers, covering more than 40% of the cost of the product.
Program Monitoring & Evaluation
Contact information is collected for those redeeming at cash rebates and participating in the giveaways. Phone surveys will be conducted to validate usage and attitudes towards the product. The program will also be monitored for participation level and cost effectiveness.
Estimated Costs & Energy Savings
This program was closed in 2014 due to lack of participation. 2015 Hydro Estimated: Deferral Cost - $0 Associated Savings -0

Lighting Program

Program Description
The objective of this program is to reduce energy use through more efficient lighting technologies in commercial buildings. The program components include rebates on a specific list of qualifying technologies, and a variety of education and marketing tools. This program has been offered through takeCHARGE since 2009.
Target Market: Commercial
This program targets the owners of commercial buildings, encouraging these customers to install more efficient lighting equipment in new construction and retrofit of existing buildings.
Eligible Measures
The eligible measures for this program have included high performance T8 lamps and ballasts, and LED exit signs. Beginning in 2013, additional measures will be eligible, including T8 and T5 fluorescent fixtures used in areas with high ceilings, such as warehouses, gymnasiums, arenas and garages.
Delivery Strategy
Delivery will be integrated with other takeCHARGE commercial sector programming. Marketing for this program will include partnering with lighting manufacturers, distributors, electrical contractors and lighting service providers as key market influencers and allies. The program will create business opportunities for trade allies to sell more efficient lighting products. The program will also target commercial property owners through direct marketing and through industry associations such as the Building Owners and Managers Association. Tools and tactics will include trade ally and business association activities, such as workshops for distributors, contractors and building operators, retail point-of-sale materials, website and advertising in trade publications. Demonstration projects will be selected from program participants. Rebates will be processed both through distributor point-of-sale and through customer application, depending on the lighting measure.

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Lighting Program

Market Considerations

Use of high performance T8 fluorescent lighting has increased since the program was introduced. Approximately 60% of fluorescent ballasts sold annually are now high performance T8, rather than less efficient T12 or standard T8. However, less than 25% of fluorescent lamps are a high performance type. Some high efficiency technologies, such as T5 fluorescent high bay lighting, are now widely used in new commercial construction, but are used less frequently in existing buildings.

High performance fluorescent lighting systems use 25% to 40% less energy than standard fluorescent systems. LED technologies, such as LED exit signs, use 80-90% less energy than fixtures with incandescent lamps. The eligible technologies are widely available through existing channels. The primary market barriers include higher initial cost and lack of understanding of appropriate lighting technologies and savings potential.

Incentive Strategy

Program incentives reduce the cost differential for higher efficiency products and also provide a sales incentive to participating lighting distributors to sell high performance T8 lighting, ballasts and lamps to their customers. The incentives offered are $1.25 for lamps and $4.25 for ballasts. The incentive for exit signs is $21.00 per unit. The incentive for T8 and T5 fluorescent fixtures is estimated to be $60 per T5 fixture for replacement of 400 watt and 250 watt metal halide fixtures in high bay and $55 per T8 fixture for medium bay applications. Pricing of some eligible measures has increased materially in the past 12 to 18 months. This largely reflects international supply dynamics. As a result, incentive levels will be reviewed annually to ensure consistency with incremental costs.

Program Monitoring & Evaluation

The program will be monitored for participation level, service quality, and cost effectiveness and a representative sample of installations will be inspected. Formal evaluations will be conducted every two years during operation.

Estimated Costs & Energy Savings

2015 Hydro Estimated:

Deferral Cost - $59,000

Associated Savings -16 MWh/yr

Isolated Systems Business Efficiency Program

Program Description

The objective of the program is to improve electrical energy efficiency across a variety of end uses. The program components include financial incentives based on energy savings, and other supports to assist in opportunity identification and evaluation. This program provides a custom approach that will allow larger commercial customers to explore a wide range of technologies suitable to their own operations, as well as an engineered track that allows for smaller customers to assess opportunities for common end uses.

Target Market

Non-residential customers in Hydro's isolated diesel and L'Anse au Loup systems are eligible.

Eligible Measures

Eligibility of the measure is based on engineering analysis of the savings. Technologies would include, but not be limited to, lighting, (heating ventilation air conditioning) HVAC, compressed air and others.

Delivery Strategy

For the engineered track, customers are able to utilize spreadsheets to assess their savings and potential rebates for common end uses, including:

- Commercial lighting – Interior, High bay or Directional
- Unitary A/C equipment (i.e. roof top units)
- Variable speed drives for fans or pumps
- Compressed air

The engineered track allows customers' progress to be incented based on their actual savings and baselines, unlike the traditional prescriptive incentive. Hydro staff will work with customers to determine baselines and estimates of savings based on the suggested retrofit. The custom track involves a walkthrough audit and feasibility analysis to determine savings and eligible incentive. This allows for a wide range of eligible technologies and projects.

The program is managed internally with some external engineering verification of projects. The Utility facilitates customers through the appropriate processes to evaluate and implement approved projects. This model has been used successfully in other jurisdictions.

Isolated Systems Business Efficiency Program

Market Considerations

Barriers to efficiency in the commercial market include financial and human resource concerns. Incentives will assist in making energy efficiency upgrades more accessible. Human resource concerns are around awareness and knowledge of the technology options as well as time to develop the business case for retrofit projects.

The isolated systems have additional challenges with access to product and access to specific technical skill sets in the evaluation of projects and technology. Hydro's program staff will assist in addressing those gaps.

Incentive Strategy

Incentives will include rebates based on energy savings, as well as funding assistance for feasibility and engineering analysis of opportunities. Rebate levels and available engineering assistance will vary based on forecasted savings and scale of the project.

Program Monitoring & Evaluation

The program will be monitored for participation level, service quality, and cost effectiveness, and include site visits, engineering reviews and other methods of verifying savings.

Estimated Costs & Energy Savings

2015 Hydro Estimated:

Deferral Cost - $68,000

Associated Savings -232 MWh/yr

Business Efficiency Program

Program Description
The objective of this program is to improve electrical energy efficiency in a variety of commercial facilities and equipment types. The program components include financial incentives based on energy savings, and other financial and educational supports to enable commercial facility owners to identify and implement energy efficiency projects.
Target Market: Commercial
This program targets existing commercial facilities that can save energy by installing more efficient equipment and systems. The program will include a custom projects approach which will appeal primarily to large commercial customers with annual energy consumption of 1,000,000 kWhs or greater. The program will also include rebates for specific measures on a per unit basis, which will appeal to small to medium commercial customers as well.
Eligible Measures
Custom projects' eligibility will be based on engineering review and verification of estimated energy savings impacts. Specific measures eligible for per unit rebates will include HVAC equipment, refrigeration, motors and variable speed drives. It is expected that the initial list of eligible technologies will be expanded as the program matures based on program experience and market opportunities.
Delivery Strategy
For this program, the utility will manage the delivery and take the role of facilitator and consultant, supporting commercial customers to complete project proposals and implement approved projects. The program will utilize external engineering consultants for evaluation of larger project proposals and for monitoring and verification of energy savings. The program will target equipment suppliers, service providers and consultants as key market influencers and allies in the promotion of energy efficient equipment. Rebates which reduce the cost of efficiency upgrade projects also provide a sales opportunity for these trade allies. Direct marketing to commercial facility owners and to industry associations will support the sales efforts of equipment and service providers.

Business Efficiency Program

Market Considerations

The custom project approach requires one-on-one support for project design and delivery at larger commercial facilities. The lifecycle for each custom project will be measured in months rather than weeks due to project planning and implementation timelines as well as post-installation verification and evaluation. This type of program requires that facilities have business and financial stability to continue operations for a time period appropriate to achieve cost effective savings.

Rebates for specific measures will appeal to a broad range of customers, providing a simpler approach for program participation.

Incentive Strategy

Incentives for this program include rebates based on $0.10 per kWh of energy savings in the first year of implementation. Financial support will also be available for facility energy audits and feasibility studies, if required, based on 50% cost sharing. Guidelines for maximum incentive per project and for scheduling incentive payments for custom projects will be determined in the program detailed design phase. A list of rebates will be developed to reflect incremental cost for specific measures on a per unit basis or based on energy use and hours of operation (for example, lighting controls or thermostats).

Program Monitoring & Evaluation

The program will be monitored for participation level, service quality and cost effectiveness, including engineering review and inspection of all custom projects and assessment of long-term impact on customer processes. Formal program evaluations will be conducted within the first year of implementation and every two years during operation.

Estimated Costs & Energy Savings

2015 Hydro Estimated:

Deferral Cost - $68,000

Associated Savings -500 MWh/yr

Industrial Energy Efficiency Program

Program Description

The objective of this program is to improve electrical energy efficiency in a variety of industrial processes. The program components include financial incentives based on energy savings, and other supports to enable industrial facilities to identify and implement efficiency and conservation opportunities. This program is a custom program to respond to the unique needs of the industrial market, rather than a prescriptive technology approach.

Target Market: Industrial

This program targets new and existing industrial process equipment in the transmission level customers served by Newfoundland and Labrador Hydro.

Eligible Measures

Eligibility of projects is based on engineering review and confirmation of estimated energy savings impact. Technologies include, but are not limited to, compressed air, pump systems, process equipment and process controls.

Delivery Strategy

The program is managed internally with external engineering verification of projects and monitoring and evaluation of energy savings. The utility takes the role of facilitator and consultant in providing methods for industrial customers to complete project proposals and implement approved projects. This program model has been used successfully in other jurisdictions.

This program was launched as a pilot program in 2009. With the first project applications being submitted in 2011, the pilot was closed to new projects at the end of 2013. A review of the pilot was conducted by CLEAResult to assess opportunities for moving forward. Findings indicate there continues to be a strong interest from Industrial Customers in participating. CLEAResult's recommendations will be used to develop a continued plan to ensure relevant programming is available to the industrial sector.

Industrial Energy Efficiency Program

Market Considerations

This market requires a one-on-one approach to project design and delivery. The program builds on the work already completed by the industrial customers, and addresses their unique barriers to improved efficiency, which include, but are not limited to, access to capital and human resources.

The lifecycle for each program transaction will be measured in months rather than weeks because of the need for review, contract development, implementation timelines and post-installation monitoring and evaluation. This type of program requires that facilities have financial and business stability to continue operations for a time period appropriate to achieve cost effective savings.

Incentive Strategy

Incentives for this program include rebates based on energy savings, as well as funding assistance for additional enabling mechanisms.

Program Monitoring & Evaluation

The program will be monitored for participation level, service quality, and cost effectiveness, including engineering review and inspection of all projects and assessment of long-term impact on customer processes. Formal program evaluations will be conducted every two years during program operation.

Estimated Costs & Energy Savings

2015 Hydro Estimated:

Deferral Cost - $5,000

Associated Savings –none for 2015

Appendix B:

Five-Year Conservation Plan: 2016 - 2020

FIVE-YEAR CONSERVATION PLAN:
2016 – 2020

newfoundland labrador hydro
a nalcor energy company

NEWFOUNDLAND POWER
A FORTIS COMPANY

October 2015

CONTENTS

1.0 EXECUTIVE SUMMARY

Newfoundland and Labrador Hydro ("Hydro") and Newfoundland Power have offered customer energy conservation programs on a joint and coordinated basis under the *takeCHARGE* brand since 2009. These programs provide a range of information and financial supports to help customers manage their energy usage.

The joint *Five-Year Conservation Plan: 2016-2020* (the "2016 Plan") builds on this experience, and continues to reflect the principles underlying two previous joint, multi-year conservation plans developed by Hydro and Newfoundland Power (the "Utilities").[1] It reflects refinement of the opportunities identified in a recently updated conservation potential study (the "2015 CPS") through in-depth local market research and program cost benefit analysis.

The 2016 Plan represents both growth and evolution of the Utilities' joint customer energy conservation program portfolio. It includes a new behavioural-based program for the residential sector, expansion of existing commercial programs, and the reshaping or discontinuation of several programs. The approach outlined in this plan will remain flexible to address the changing provincial landscape, in terms of customer expectations, market conditions for energy efficient products, and electrical system costs. The 2016 Plan also addresses customer support and education, program planning and evaluation processes, as well as the Utilities' costs and cost recovery arrangements.

The total estimated energy savings for 2016 through 2020 are 883 GWh.[2] Total estimated costs through this period are $41.1 million.

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[1] The *Five-Year Energy Conservation Plan: 2008-2013* was filed with the Board on June 27, 2008. The *Five-Year Energy Conservation Plan: 2012-2016* was filed on September 14, 2012.

[2] The energy savings indicated throughout the *Five-Year Energy Conservation Plan: 2016-2020* represent *gross* energy savings achieved by customers. These savings reflect all technologies installed by participating customers since program implementation. *Net* energy savings would reflect adjustments for: (i) the timing of customer installations giving rise to the energy savings; and (ii) program *free ridership* (an estimate of participants who would have chosen the more efficient product without the program).

2.0 BACKGROUND

2.1 Planning Context

Hydro and Newfoundland Power have collaborated on customer energy conservation program planning and delivery for the past 8 years. The programs offered jointly under the takeCHARGE brand have included a variety of information and financial supports which help customers manage their energy usage. The Utilities' provision of energy conservation programming is responsive to customer expectations, supports efforts to be responsible stewards of electrical energy resources and is consistent with provision of least cost, reliable electricity service. Initiatives address conservation opportunities for customers in each sector: residential, commercial and industrial.

The Utilities' practice has been to refresh their joint strategic plans for customer conservation programming every three to four years. This ensures programs achieve long term goals while being responsive to changes in customer expectations, market barriers, technology developments, and economics. Current program offerings are based on the Five Year Energy Conservation Plan: 2012-2016 ("the 2012 Plan").

One of the key inputs into the 2016 Plan was the outcome of the Conservation Potential Study ("CPS"), completed by the Utilities in 2015. The CPS identified cost-effective energy and demand reduction measures, outlined general parameters for program development, and quantified achievable energy savings potential by sector and end-use. The results of the CPS are considered with the Utilities' experience and other factors in the local market to determine potential programs and energy saving targets for the 2016 Plan.

The Utilities' conservation planning is coordinated with overall planning for the electrical system. Significant changes to the Island Interconnected System are anticipated to occur in this planning period. Interconnection of the Muskrat Falls hydroelectric development is forecast for 2018 and will include the Island's first connection to the

North American grid. As a result, there is uncertainty with respect to the marginal cost of energy and capacity on the Island Interconnected System beyond 2017.

Schedule A provides the current forecast marginal cost of energy and capacity for 2015-2035.[3] The forecast indicates a decrease in the marginal cost of energy beginning in 2018. This effectively reduces the value of energy savings arising from customer energy conservation programming, and limits the types of programs that can be cost effectively offered.

Costs of electricity supply additions are expected to be incorporated into customer rates starting in 2018, putting upward pressure on customers' rates. This is expected to increase customers' motivation to conserve energy to manage their electricity costs. Also, the recent economic slowdown is anticipated to continue into this planning period and will influence customer behaviour with regards to conservation.

The 2008 and 2012 Five Year Conservation and Demand Management Plans, delivered jointly by the Utilities, had focused primarily on energy conservation. This reflected the relatively high marginal energy costs (predominantly due to fuel costs at Hydro's Holyrood Thermal Generating Station) which justified such a focus. The events of recent winters have since brought to light issues with peak load and generation capacity on the Island Interconnected System which are anticipated to continue into this planning period. The 2016 Plan therefore considers demand management opportunities as well as energy conservation.

The Utilities have been offering some form of customer energy conservation programming since 1991, and have achieved significant energy savings over this time. The current forecast, particularly for insulation, anticipates diminishing returns. For example, the remaining potential for energy savings through insulation upgrades has

[3] The marginal costs used to determine cost effectiveness of the customer energy conservation programs are based on the most recent marginal cost forecast as projected by Hydro in February 2015. These estimates are currently under review by Hydro to incorporate the forecast interconnection with the North American grid. Once more current estimates are available, they will be incorporated in the screening process.

been impacted by changes to the National Building Code requiring basement insulation in new homes, as well as barriers to retrofitting many of the eligible existing homes. This is consistent with experience in other North American jurisdictions where utility programming has harvested the "low hanging fruit" and subsequently has moved on to address more challenging and costly opportunities.

Energy conservation programming has also been affected by technology advancements and changes to standards. Lighting product standards changes have effectively eliminated availability of incandescent bulbs for consumers. At the same time, LED technology has advanced and become more affordable and available. The pace of this change has been even faster than anticipated in the 2012 Plan. This is demonstrated by higher than projected uptake in the Utilities' Instant Rebate component of the Small Technologies program.

The Utilities continue to work with the Provincial Government, through the Office of Climate Change and Energy Efficiency, regarding policy development for energy conservation and efficiency, and particularly potential impacts and approaches to building codes, product standards and broader market transformation objectives.

Many of the influences on the provincial energy conservation market can be seen in other North American jurisdictions. In recent years, many jurisdictions have experienced decreasing marginal costs of energy and increasing program costs due to maturing conservation programs. As a result, utilities and program administrators have revised their approach to economic analysis of energy conservation. The Utilities have conducted research on current economic evaluation practices. A summary of this research is provided in Schedule B. It indicates that Canadian jurisdictions use the Total Resource Cost ("TRC") test as their primary benefit cost test for program screening, with the Program Administrator Cost test as a secondary test. Only one of the seven Canadian utilities researched used Ratepayer Impact Measure as a primary benefit cost test for program screening. In the United States, most jurisdictions follow similar practices with over 70% using TRC as the primary benefit cost test and 2% using Ratepayer Impact Measure for program screening.

2.2 Energy Conservation Programs

Based on the 2012 Plan, the Utilities have jointly offered customer energy conservation programs which provide both information and financial incentives to encourage customer installation of energy efficient technologies.[4] In addition, Hydro has offered programming for its customers, such as incentives for commercial customers in its isolated system service territories, where market conditions and system costs differ.

Table 1 shows, by sector, the portfolio of programs that have been offered under the 2012 Plan.[5]

Table 1
Conservation Programs
By Sector

Residential	**Commercial**	**Industrial**
Insulation Thermostat ENERGY STAR Window[6] HRV Block Heater Timer Small Technologies Isolated Systems Community Program	Lighting Business Efficiency Program Isolated Business Efficiency Program	Industrial Energy Efficiency Program

[4] Once installed, these more energy efficient technologies provide energy savings for the customer throughout the life of the product. For example, an HRV has an estimated life of 15 years and will result in energy savings benefits throughout that period.

[5] The Utilities also engage in demand management activities, including Newfoundland Power's Curtailable Service Rate Option and Hydro's interruptible load arrangements with its Industrial Customers.

[6] The ENERGY STAR Window Program concluded at the end of 2014.

Schedule D summarizes the energy savings and costs for the customer energy conservation programs offered by the Utilities from 2009 through 2015.

Residential Programs

Table 2 provides a summary of residential customer energy savings achieved through the Utilities' conservation programs from 2009 through 2015(F).[7]

Table 2
Residential Portfolio Energy Savings
2009 through 2015F
(GWh)

	2009	2010	2011	2012	2013	2014	2015F	Total
Energy Savings	2.5	7.1	18.6	28.5	38.4	51.5	65.7	**212.3**

The takeCHARGE residential programs are expected to result in aggregate energy savings of approximately 212.3 GWh by the end of 2015.[8]

Insulation Program

As a result of the updates to the National Building Code in 2012, several changes were made to the Insulation Program. New homes are no longer eligible and the minimum R-value requirements for existing homes have been increased. As well, the rebate structure was revised to provide a higher, easy-to-calculate rebate. Customers can receive an incentive of 75% of basement wall or ceiling insulation material costs up to $1,000, and 50% of attic insulation material costs up to $1,000.

[7] Energy savings include savings arising from all technologies installed by all participants since program implementation. This reflects the fact that these technologies provide energy savings benefits for the customer throughout the life of the product.

[8] Since implementation in 2009, there have been approximately 36,650 participants and over 638,000 at-the-cash rebates were provided on energy efficient products in the takeCHARGE residential customer programs.

Thermostat Program

High efficiency programmable and electronic thermostat replacements allow customers to conserve energy at relatively low cost and effort. Eligibility for the programs is limited to electrically heated homes, determined on the basis of annual energy usage.

ENERGY STAR Window Program

This program concluded at the end of 2014. After 5 years, and over 9,200 participating customers, the program had achieved its objective of making more efficient windows the standard in the local market.

Heat Recovery Ventilator Program

This program promotes the installation of high efficiency heat recovery ventilators ("HRVs"). HRVs have been widely used in new home construction in the province since the 1990s, to control humidity and air quality. The HRV program has experienced lower than projected participation since its launch in late 2013.[9] There has been improvement in 2015, and the Utilities will continue to monitor and evaluate this program in order to find opportunities to increase participation.

Block Heater Timer Program

Hydro provided giveaways and at-the-cash coupons for block heater timers to customers in Hydro's Labrador Interconnected System from 2012-2014. While vehicle engine block heaters are used extensively in this area, timers are rarely used. Instead of using electricity throughout the night, block heater timers allow vehicle owners to reduce the amount of time that electricity is used to warm the vehicle engine. Due to lack of participation this program was not continued past 2014 but commercial customers can take advantage of this technology through the Business Efficiency Program ("BEP") or the Isolated Systems Business Efficiency Program ("ISBEP").

[9] The Utilities have received feedback regarding low customer knowledge of home ventilation, with many customers being unaware of the purpose of a HRV in their home and how it can save energy. Also, there are complexities in the supply chain for acquiring a high efficiency HRV which can be problematic for potential participants.

Small Technologies

The small technologies program is supported by retail partners and appeals to a broad customer group as it does not involve a major home renovation. The program uses different marketing approaches for two different groups of energy efficient products.

The Instant Rebate component offers relatively small incentives instantly at-the-cash on a variety of low cost, every day energy efficient products for the home.[10] Participation and energy savings results in the first two years of the program have exceeded the forecast in the 2012 plan. The Appliance and Electronics component offers incentives that are relatively higher value and available by mail-in and online application throughout the year.[11]

Isolated Systems Community Program

Following two pilot programs in 2010 and 2011, Hydro launched a full-scale, energy efficiency direct install program in 2012. The program includes direct installations of energy efficient products at no cost to homes and businesses.[12] The program also focuses on customer education and building capacity in the communities by hiring and training local representatives. These representatives work in their own communities to promote the program, provide information on energy use, and install the products.

[10] Products include LED lighting, motion sensors, timers, dimmer switches, smart power strips and more.

[11] Products include energy efficient clothes washers, full-size refrigerators, full-size freezers and TVs.

[12] Products include low-flow showerheads and aerators, CFLs, smart power strips, and hot water tank and pipe insulation.

Commercial Programs

Table 3 provides a summary of commercial customer energy savings achieved through the Utilities' conservation programs from 2009 through 2015(F).

Table 3
Commercial Portfolio Energy Savings
2009 through 2015F
(GWh)

	2009	**2010**	**2011**	**2012**	**2013**	**2014**	**2015F**	**Total**
Energy Savings	0.2	0.9	2.4	3.3	3.9	6.5	11.4	**28.6**

The takeCHARGE commercial programs will result in estimated aggregate energy savings of approximately 28.6 GWh by the end of 2015.[13]

Commercial Lighting Program

The Commercial Lighting Program targets reduced energy use through efficient lighting in commercial buildings, including high performance T8 and T5 fluorescent lighting and LED exit signs. This program has primarily been promoted through local lighting distributors by discounting lighting products at time of purchase.

The Business Efficiency Program

The objective of this program is to improve electrical energy efficiency in a variety of commercial facilities and equipment types. The program components include financial incentives based on energy savings from custom projects, and other financial and educational supports to enable commercial facility owners to identify and implement energy efficiency improvement projects. It also includes rebates for specific measures on a per unit basis.

[13] Since implementation in 2009, there have been over 1,050 participants in the takeCHARGE commercial customer programs.

Isolated Systems Business Efficiency Program

This program is targeted toward commercial customers located in Hydro's isolated system communities. This custom program provides incentives based on the energy savings from efficiency improvement projects. This allows customers to implement energy efficient technologies that are suitable for their specific buildings, equipment and operations.

Industrial Programs

Table 4 provides a summary of industrial customer energy savings achieved through Utility customer energy conservation programs from 2009 through 2015(F).

Table 4
Industrial Program Energy Savings
2009 through 2015(F)
(GWh)

	2009	2010	2011	2012	2013	2014	2015(F)	Total
Energy Savings	-	-	0.2	3.3	3.3	25.6	25.6	58.0

The takeCHARGE Industrial Energy Efficiency program will result in estimated aggregate energy savings of approximately 58.0 GWh by the end of 2015.[14]

The Industrial Energy Efficiency Program is a custom program that responds to the unique needs of Hydro's transmission level industrial customers. This program provides financial support for engineering feasibility studies of efficiency projects and for project implementation costs. The Industrial program was initially launched as a three-year pilot program in 2009, with the first project applications being submitted in 2011 and the last being submitted in 2013. No projects were completed in 2013 as focus was put on feasibility studies for work to be completed in 2014. The program then underwent an assessment by an external third party in 2014 and was re-launched as a full program in 2015.

14 Since implementation in 2009, there have been 5 projects completed under the takeCHARGE Industrial Energy Efficiency Program.

2.3 Education & Support

The Utilities continue to provide energy efficiency education and support to customers through a variety of channels, which include a joint website, outreach activities, school presentations and partnerships with other organizations.

Table 5 shows the number of customer-initiated contacts with the Utilities for energy conservation information from 2010 through 2015 YTD.

Table 5
Customer Contacts for
Energy Conservation Information

	2010	2011	2012	2013	2014	2015YTD
Contact Centre Inquiries	11,704	12,624	9,793	9,630	10,830	5,328
Website Visits	52,013	72,996	49,202	76,278	186,003	197,973

The majority of customers chose electronic means of communication with the Utilities to obtain information on energy conservation and rebate programs. This is consistent with promotion of the takeCHARGE website as the primary resource for customer inquiries and information. Customer visits to the takeCHARGE website grew by 144% from 2013 to 2014. Activity in the first eight months of 2015 shows continued growth, with approximately 80% of website visits via a mobile device. This increase is related to increased promotion, changes to existing programs, and addition of new programs.

The Utilities have participated in an average of 214 community outreach events each year since 2012. This included presentations to retailers and suppliers, senior citizens, trade allies and other groups. takeCHARGE information booths were displayed at home shows, trade fairs, and retail stores across the province. The Utilities also offer a number of outreach events, such as the annual takeCHARGE of Your Town Challenge and Energy Efficiency Week. Through these outreach activities, members of the takeCHARGE team assisted customers with their energy efficiency questions, while raising awareness of energy conservation and the takeCHARGE rebate programs.

Over the last three years the takeCHARGE *Kids in Charge* K-I-C Start school program, has provided energy efficiency and conservation education support to students throughout Newfoundland and Labrador. This has included delivering in classroom presentations and an annual contest for primary and elementary students. In 2014, takeCHARGE partnered with the Provincial Office of Climate Change and Energy Efficiency to extend this program through the Hotshots pilot program.[15] As a result, in 2014-15 school year, over 11,000 students in 106 schools throughout the province participated in 448 presentations about energy conservation.

Trade allies play an integral role in helping customers make knowledgeable decisions regarding energy conservation and related home improvements. Retail partners display information about takeCHARGE programs and energy efficiency products in their stores and in flyers, as well as during special promotional events.[16] Similarly, the Utilities are continuing to grow a network of business to business service providers and suppliers that support the commercial and industrial sectors.[17]

The Utilities have also developed partnerships with a variety of other organizations that share common goals for the province's conservation market, including the Association of Newfoundland and Labrador Realtors, the Canadian Home Builders Association, Newfoundland and Labrador Housing Corporation, and the Canadian Mortgage and Housing Corporation.

[15] Through the HotShots pilot, the Province provided funding and support for additional in-class presentations, curriculum linked teacher materials, and a contest for high school students.

[16] The Utilities continue to work with over 160 retail store partners, 11 manufacturers/distributors, and approximately 50 HRV installers.

[17] These include lighting equipment manufacturers and distributors, electrical and HVAC contractors, and engineering firms.

Table 6 shows costs for education and support for the period 2009-2015(F).

Table 6
Conservation Education & Support
Costs 2009-2015(F)
($000s)

	2009	2010	2011	2012	2013	2014	2015(F)	Total
Education	666	486	428	426	501	647	693	3,847
Support	236	206	219	222	186	174	158	1,401
Total	**902**	**692**	**647**	**648**	**687**	**821**	**851**	**5,248**

2.4 Planning & Evaluation

Planning

The focus of the Utilities' CDM planning process is to develop a 5-year plan for the implementation of comprehensive customer energy conservation and demand management programs around the technologies that were determined to have conservation potential in the provincial market. The completion of the CPS in 2015 effectively initiated the development of the 2016 Plan.

Programs are developed and revised through consultation with the various market stakeholders, such as government, trade allies and local interest groups, to gather feedback on program delivery strategy.

Table 7 shows costs for conservation planning for the period 2009-2015(F).[18]

Table 7
Conservation Planning
Costs 2009-2015(F)
($000s)

	2009	2010	2011	2012	2013	2014	2015(F)	Total
Planning	401	429	509	404	462	958	1,202	4,365

Variations in annual conservation planning costs primarily reflect the periodic nature of the Utilities' program planning and research activities.

Research

In 2013, the Utilities completed a joint Commercial Facility Equipment Inventory ("CFEI") on 54 commercial facilities.[19] This research provided information on how commercial customers use electricity, through an inventory and analysis of all mechanical and electrical equipment in each facility.[20] This data was used as a direct input into the CPS conducted in 2015.

In 2014, Newfoundland Power and Hydro jointly conducted a survey to gather information regarding electricity end uses in the residential sector. The information gathered was used to assess potential electricity savings opportunities, and was used as a direct input into the current planning cycle. These results are also being taken into account in making adjustments to the *takeCHARGE* programs. For example, because

18 Conservation planning costs include costs related to surveys and research, development of the potential study and the five-year plan, and general administration.

19 The CFEI was completed by CBCL Limited, a consultant that conducted on-site facility audits for participating commercial customers. CBCL Limited is a leading employee owned multidisciplinary engineering and environmental consulting firm in Atlantic Canada.

20 The CFEI found, for example, that the food retail sector are the largest users of electricity on a square footage basis of the customers audited, followed by the manufacturing/fish processing sector.

of survey findings regarding the prevalence of CFLs, these have been removed from the Instant Rebates Program beginning in the fall of 2015.[21]

Newfoundland Power completed research on ductless mini-split heat pumps ("MSHP") from 2013 to 2015. The objectives of this research were to assess the current MSHP market in Newfoundland, the use of the MSHP as a supplementary heat source and the potential impact of MSHPs on the electricity system. The results indicate that MSHP are more efficient and do save energy compared to electric baseboard heat.[22] This analysis also shows that there is not likely to be peak demand reduction on the electricity system from installation of MSHPs.[23] Customer demand for MSHP products has grown significantly in recent years and continues to be strong. However, there are issues with availability of qualified installers and customer understanding of product quality requirements.

In the fall of 2014, Newfoundland Power launched a pilot program to assess the economic, market, and technical feasibility of direct load control to reduce overall peak demand. This pilot was initiated in response to the constraints on system capacity that became evident after the events in January of 2013 and 2014. The pilot involved controlling hot water tanks in approximately 500 customer homes in Paradise and Mount Pearl. Demand reduction achieved by the direct load control events on average was 0.6 kW per participant, and for events that included all participants, approximately

[21] Customers were asked what types of lighting they use in areas of their house where they spend the most time: 63% reported that they use incandescent bulbs, 53% CFLs, and 18% LEDs (multiple responses allowed). In another question, 31% of respondents claimed to have changed all their bulbs to more energy efficient types, and 45% indicated that they have begun to change to more energy efficient types.

[22] Approximately half of the homes in the study recorded energy savings after installation of the MSHP. In these homes, electricity usage declined by an average of 5,300 kWh or 19% per year, with savings ranging from 7% to 50%. The remaining homes recorded an increase or no change in energy usage. This appears to reflect factors such as heating of additional living space, fuel switching, or operational issues with the MSHP.

[23] Savings at time of system peak are dependent on a number of factors such as the efficiency and defrost cycle of the MSHP system, and temperature. A high efficiency MSHP may be capable of providing peak savings in warmer parts of the province but not in colder regions, while a less efficient MSHP may not be capable of providing peak savings in any region. On colder weekdays, the study observed little difference in the load profile of the MSHP homes vs. electric baseboard homes, and occasionally the MSHP homes' peak load was slightly higher.

298 kW of demand reduction was achieved. The Pilot results also indicate that a full scale provincial program does not meet the economic requirements.

The Provincial Office of Climate Change Home Energy Monitoring Pilot Project, which is supported by the Utilities and administered by Hydro, began in September 2014 and aims to assess whether real time display of energy use has a positive effect on electricity conservation behavior. The pilot involves approximately 750 customers: 250 with an in-home display device, 250 with an in-home display device as well as electricity conservation information in a monthly mail out, and 250 with only the electricity conservation information. Monitoring of participants will continue until January 2016 and the final report will be submitted to Government by end of March 2016.

Evaluation

The customer energy conservation programs are continuously evaluated by the Utilities on their energy savings, market impacts and delivery process effectiveness. Additional review by external third party evaluators has also been conducted. Program evaluation findings are used to refine program design and implementation details on an ongoing basis, as well as support further planning.

For example, the third party residential program evaluation in 2013 found that two-thirds of windows sold in the province were ENERGY STAR, which supported the Utilities' decision to conclude the ENERGY STAR Windows Program.[24]

Economic and energy savings evaluation of the customer energy conservation programs is performed annually. Program participants are required to provide certain information on program rebate applications. This information ranges from technical data, such as the R-value of installed insulation, or efficiency rating of a HRV to the type of heating in the home and its geographic location. Analysis of this data allows the

[24] The 2013 residential program evaluation was conducted DNV GL- Energy, headquartered in Burlington, Massachusetts, and specializing in evaluating programs that promote energy efficiency, demand response, and distributed generation.

Utilities to accurately estimate the energy savings for each program and perform industry standard economic cost-benefit tests.

2.5 CDM Costs & Cost Recovery

Table 8 provides a summary of the customer energy conservation program and general costs of the Utilities from 2009 through 2015(F).[25]

Table 8
Conservation Costs
2009 through 2015 (F)
($000s)

	2009	2010	2011	2012	2013	2014	2015F	Total
Programs								
Residential	1,386	2,322	3,473	3,436	3,921	4,277	5,188	24,003
Commercial	79	95	216	214	355	926	1,388	3,273
Industrial	57	226	103	173	89	1,244	19	1,910
Total Programs	1,522	2,643	3,791	3,823	4,365	6,447	6,595	29,186
General	1,303	1,121	1,156	1,052	1,149	1,779	2,054	9,614
Total	**2,825**	**3,764**	**4,947**	**4,875**	**5,514**	**8,226**	**8,649**	**38,800**

The Utilities' costs related to conservation programs have increased from approximately $2.8 million in 2009 to $8.6 million in 2015. This primarily reflects the addition of new customer energy conservation programs in 2013, specifically the Small Technologies Program and the Business Efficiency Program. This also reflects the increased levels of customer participation and rebates related to the joint takeCHARGE program portfolio. The expansion of customer programs has also resulted in increasing energy savings.

[25] This cost summary does not include (i) costs related to programs offered independently by the Utilities prior to June 2009; (ii) costs related to Newfoundland Power's demand management activities (Curtailable Service Rate Option and facilities management); and (iii) costs related to Hydro's interruptible service arrangements with its Industrial Customers.

Details of the Utilities' customer energy conservation program and general costs are provided in Schedule C.

The Utilities each bear the costs related to the provision of customer energy conservation programming in their own service territory. General conservation and program costs, such as customer rebates and costs related to responding to customer inquiries are incurred directly by each utility. Costs which are incurred jointly, such as provincial mass media advertising, are split on an 85% / 15% basis between Newfoundland Power and Hydro, respectively.[26]

Cost Recovery

Newfoundland Power's current conservation cost recovery practice reflects Board Order No. P.U. 13 (2013). Conservation program costs are deferred and amortized over a seven-year period. Through the annual operation of the Company's Rate Stabilization Adjustment, customer rates are adjusted to reflect any difference between the conservation program costs included in the most recent test year and the costs actually incurred. Newfoundland Power's annually recurring general conservation costs related to providing general customer information, community outreach and planning are expensed in the year in which the costs are incurred.

Hydro's current customer rates, as approved by the Board in Order No. P.U. 8 (2007), include recovery of approximately $0.4 million in costs related to management and planning of conservation programming. In each year from 2009 to 2014, inclusive, Hydro has deferred recovery of direct program costs related to the expansion of customer energy conservation programming under the 2008 Plan and 2012 Plan.[27] As of August 14, 2015, associated with a general rate application filed by Hydro on July 30, 2013, and an amended general rate application filed by Hydro on November 10, 2014,

[26] This approach to division of jointly incurred costs reflects the proportion of customers served by each utility.

[27] The deferred recovery of these costs in 2009, 2010, 2011, 2012, 2013, and 2014 were approved by the Board in Order Nos. P.U. 14(2009), P.U. 13(2010), P.U. 4(2011), P.U. 3(2012), P.U. 35(2013), and P.U. 43(2014), respectively.

the Consumer Advocate, Newfoundland Power, the Industrial Customer Group and Vale, with participation by Board Hearing Counsel, have engaged in negotiations with Hydro. As a result, these parties agreed that "Hydro's proposal to defer and amortize annual customer energy conservation program costs, commencing in 2015, over a discrete seven year period in a Conservation and Demand Management (CDM) Cost Deferral Account should be approved."[28]

3.0 PLAN: 2016-2020

3.1 Conservation Potential & Program Selection

The programs included in the 2016 Plan have been selected based on a number of considerations. Opportunities identified in the 2015 CPS are a key input and these have been further assessed by the Utilities in terms of engineering, market and economic viability. Consideration has also been given to the experience of the Utilities and others in the local marketplace, feedback from customers, as well as experience shared from other Canadian jurisdictions.

Conservation Potential Study

In June 2015, a comprehensive study was completed of electricity conservation and demand management potential for the province.[29] This Conservation Potential Study estimated the potential for electrical energy and demand savings by sector and by electricity system from 2015-2029. It also identified specific technologies available to assist in achieving that potential. The CPS essentially provides a framework, consistent with current North American practices, within which to assess conservation programming. The findings enabled the Utilities to quickly focus on cost effective technologies and begin assessment of market characteristics to guide program concept development.

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[28] Newfoundland and Labrador Hydro – Amended General Rate Application – Parties' Settlement Agreement dated August 14, 2015.

[29] ICF International (previously called Marbek) conducted Conservation Potential Studies for the Utilities in 2007 and 2015. ICF International is a leading environmental and energy management consultancy and has extensive experience conducting Conservation Potential Studies in Canada.

Electrical system marginal costs of supply are used in the CPS to screen the economic viability of more efficient technologies.[30] For the current CPS, these costs were based on the most recent marginal cost forecast as projected by Hydro in February 2015.[31] These estimates are currently under review. Once Hydro's marginal cost study is completed, the CPS results will be reassessed. If such a review results in changes to the list of cost effective technologies with conservation potential, these will be considered in future updates to the 2016 Plan.

Figure 1 shows the baseline provincial energy usage forecast which was input to the 2015 CPS (the reference case), and the upper and lower achievable potentials estimated by the Potential Study.[32]

[30] Technologies are considered to be economically viable when the cost of saving one kWh or kW of electricity is equal to, or less than, the marginal cost of supplying the electricity.

[31] The 2015 CPS included an analysis of the sensitivity of potential technologies to changes in marginal costs. The analysis was based on a range of + 30% to – 10% of the February 2015 forecast marginal costs. It indicated a modest level of variability in technology viability and resulting conservation results. Please see CPS, section 7.5 Energy Efficiency Supply Curve, filed with the Board September 15, 2015.

[32] The reference case is based on the provincial energy usage forecast from 2014. After this study was completed the energy usage forecast decreased due to the economic downturn, mainly in the industrial sector. The achievable potential is defined as the portion of the economic conservation potential that is achievable through utility interventions and programs given institutional, economic and market barriers. The upper achievable potential is considered to be the best case scenario with all market barriers removed, such as capital cost and product accessibility. The lower achievable potential is considered a business as usual scenario with the existing market barriers remaining in place.

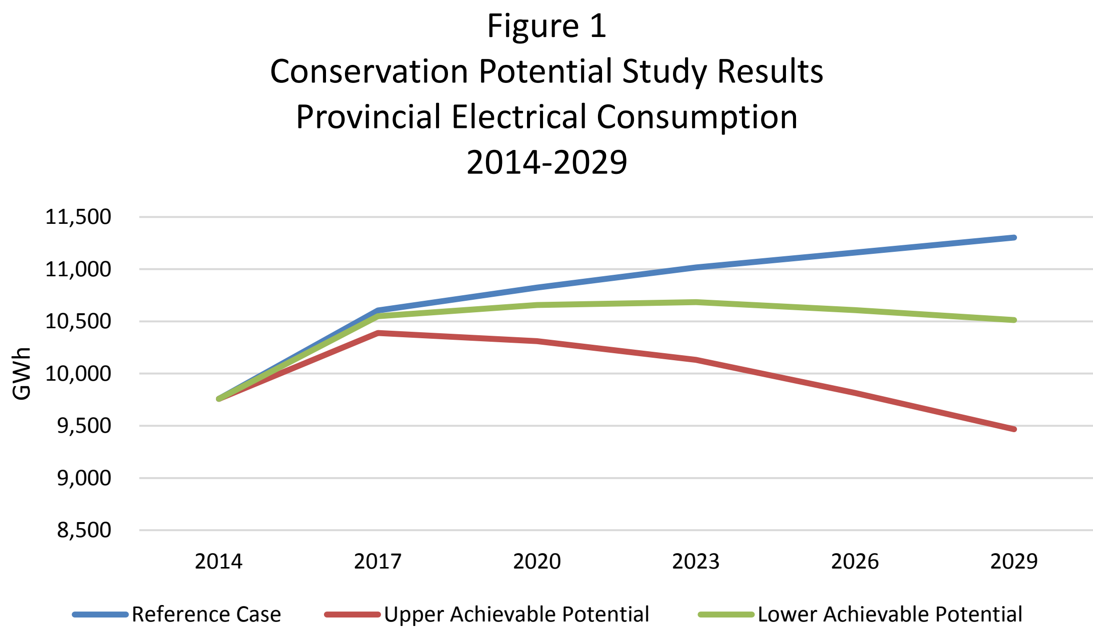


Figure 1 shows that, over time, the cumulative effects of implementing cost effective efficient technologies can significantly reduce forecast growth in electricity usage.[33]

Figures 2 and 3 show the results of the CPS regarding achievable demand reduction potential from energy efficiency measures ("Energy Efficiency") and from demand response specific measures ("Demand Response") by 2020.[34]

[33] At the end of the first estimation interval, in 2017, the CPS shows a range of 55 GWh for the lower achievable potential savings and 215 GWh for the upper achievable potential savings. This compares with annual savings of approximately 116 GWh currently estimated in the Plan for the same timeframe.

[34] The Commercial and Industrial sector includes Hydro's large transmission level Industrial customers as well as Newfoundland Power's general service customers.

Figure 2
Lower Achievable Demand Reduction Potential
Island Interconnected System
2020
(MW)

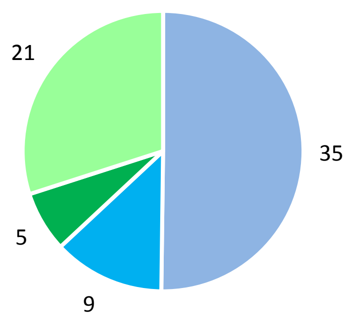
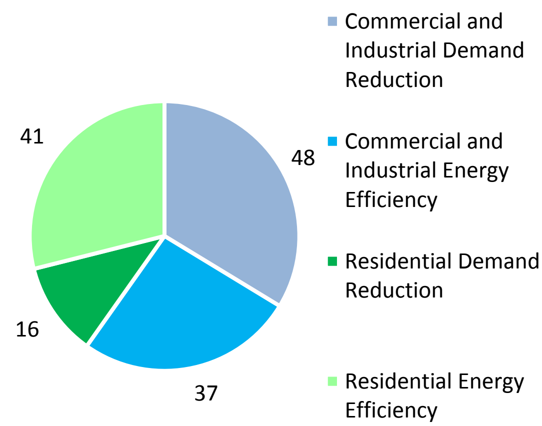


Figure 3
Upper Achievable Demand Reduction Potential
Island Interconnected System
2020
(MW)



Figures 2 and 3 show 70 MW for the lower potential and 142 MW for the upper potential demand reduction on the Island Interconnected System.[35] Installation of energy efficiency measures that reduce consumption during times of peak demand account for approximately 43% and 55% of the lower and upper achievable demand reduction, respectively, by 2020.[36]

The majority of the demand reduction potential was identified in the Commercial and Industrial sectors. Specifically, the Industrial sector represents about 87% and 74% of the total lower and upper achievable demand reduction, respectively. The demand reduction technologies identified through the CPS as having the most potential included curtailable load arrangements with commercial and industrial customers and direct load control of residential hot water tanks.

[35] 21+35+9+5=70 and 41+16+37+48= 142
[36] (21+9)/70=43% and (37+41)/142=55%.

Selection

The technologies that passed the economic screening of the CPS were reviewed in detail to assess their possible inclusion in the 2016 Plan. Local market research was conducted to identify barriers to broader adoption of more efficient technologies, such as capital cost, market availability and awareness. This included consultation with market stakeholders and trade allies, as well as discussions with other utilities.

Once existing market barriers were identified, a program strategy was then developed to attempt to overcome those barriers. Costs associated with the program were considered and the cost effectiveness of the program determined.[37] This more detailed review of program costs and benefits can cause a technology that had passed economic screening in the CPS to fail the economic tests required of CDM programs.

Economic Screening

The Utilities' economic screening of the customer energy conservation programs has previously required a positive result for both the Total Resource Cost ("TRC") and Ratepayer Impact Measure ("RIM") cost-benefit tests.[38] Recent research indicates Canadian and U.S. utility practice has changed to focus on the TRC and Program Administrator Cost ("PAC") tests.[39]

The Utilities recommend adoption of the TRC as the primary means of program economic screening, and the PAC as a secondary means. This is consistent with current North American practice, and is appropriate based on the electrical system marginal costs and program objectives in this jurisdiction. Based on this recommendation the programs included in the 2016 Plan passed economic screening

[37] Program cost estimates include marketing, delivery and administration, incentives, measurement and verification, and evaluation.

[38] In Order No. P.U.7 (1996-97), the Board required customer conservation programs to be evaluated with respect to rate impact, as well as the total resource costs. The Utilities' have interpreted this Order to require a TRC of 1.0 and a RIM of 0.8 as described in *Newfoundland Power Inc. – 2009 Conservation Cost Deferral Application, Section 2: Proposed Customer Program Portfolio* filed with the Board October 29, 2008.

[39] See Section 2.1, page 4, and Schedule B.

based on the TRC and PAC.[40] The Utilities' will continue to monitor changes to economic screening practices to appropriately reflect evolving program characteristics and electrical system costs.

3.2 Conservation & Demand Management Programs

The 2016 Plan builds on the outcomes of the 2012 plan as well as the experience of the Utilities. Programs included in the 2016 Plan address conservation opportunities in all three sectors: residential, commercial, and industrial. The 2016 Plan includes a new behavioural-based program for the residential sector, expansion of existing commercial programs, and the reshaping or discontinuation of several programs. These conservation programs are broadly consistent with programs offered by utilities in other jurisdictions.

Table 9 shows, by sector, the portfolio of programs to be offered under the 2016 Plan.

Table 9
Conservation Programs
By Sector

Residential	**Commercial**	**Industrial**
Insulation	Business Efficiency Program	Industrial Energy Efficiency Program
Thermostat	Isolated Business Efficiency Program	
HRV		
Small Technologies		
Isolated Systems Community Program		
Benchmarking		

[40] Application of the RIM test would result in elimination of a number of programs, including Benchmarking, HRV, and Small Technologies.

Residential Programs

Insulation, Thermostat and HRV Programs

These existing joint incentive programs primarily target space heating energy savings, and will continue to be offered as part of the 2016 Plan. The remaining eligible market for the Insulation and Thermostats programs has been declining in recent years. The HRV program has had limited participation due to barriers related to customer understanding and market complexity. These programs will be continuously evaluated to ensure program cost effectiveness.

Small Technology Program

The jointly offered Small Technologies program will continue to use different marketing approaches for the two different groups of energy efficient products.

The Instant Rebate component will continue to offer relatively small incentives instantly at-the-cash on a variety of low cost, every day energy efficient products for the home. As part of the 2016 Plan, Instant Rebates will include additional technologies.[41] It is anticipated that this component will end during 2018 as LED lighting becomes the norm in the residential lighting market.[42] Most of the energy savings benefits in this program are related to customers' early adoption of LED lighting from less efficient technologies, and energy savings from non-lighting products are not expected to be sufficient to offset the program delivery costs.

Incentives for the Appliance and Electronics component will continue to be available through 2017. At that time, anticipated reductions in marginal costs on the electricity system will effectively reduce the value of energy saving benefits, causing the program to fail economic screening.

41 As part of the 2016 Plan, Instant Rebates will include additional technologies, such as faucet aerators, door bottom weather stripping, door adhesive weather stripping, window insulation kits, electrical outlet gaskets, and caulking.

42 The uptake of LEDs will be monitored and evaluated to confirm the market saturation rate in 2017.

Isolated Systems Community Program

The existing format for this program will continue to be offered to customers in Hydro's isolated system communities through 2017. Information and feedback collected in 2014 and 2015, particularly for the direct install component, will be used to evaluate and plan for the Isolated Systems Community Program beyond 2017.

An Appliance Retirement component will be added to this program beginning in 2016, targeting at least one community. Older inefficient appliances will be removed from participating homes and routed for appropriate disposal.[43]

Benchmarking

This new joint program will promote customer behaviour changes to encourage more efficient energy use. Benchmarking involves using social norms to encourage neighbourly competition to reduce electricity consumption. This program will include comparison of participant households' energy consumption with their energy history and that of similar households. Participants will also receive personalized home energy reports that provide household specific electricity usage information and savings tips to help them reduce energy use and lower their electricity bills. This program will be available to customers from 2016 to 2019.

Commercial Programs

Lighting Program

Beginning in 2016, existing commercial lighting program products will become prescriptive rebates under the Business Efficiency Program, including the fluorescent high bay, high performance T8 fluorescent lamp and LED exit sign. This change will allow for more specific marketing initiatives and increased awareness of the rebates available for these technologies.

[43] This component will be evaluated to determine whether a broader program would be cost effective.

Electronic ballasts will no longer be available for incentive as of 2016 because these ballasts have become the market standard. Industry partners indicate that approximately 55% of ballasts sold in the province in 2014 meet the program efficiency criteria.[44]

Business Efficiency Program

The Business Efficiency Program, offered jointly by the Utilities, will continue to provide custom and prescriptive incentives to commercial customers for energy efficiency improvements. Continued growth in customer participation and energy savings are anticipated for this program. The Utilities will increase the customer education and awareness component of this program to include sector-based identification of energy efficiency opportunities. New technologies will also be added to the program's list of prescriptive incentives.[45]

Isolated Systems Business Efficiency Program

This program will continue through 2020, and will be offered to Hydro's commercial customers located in isolated system communities. The program will continue to provide incentives based on the energy savings of customer projects, similar to the Business Efficiency Program.

Industrial Programs

Industrial Energy Efficiency Program

Through 2020, this customized program will continue to offer support and financial incentives based on energy savings for retrofit of industrial process equipment for Hydro's transmission level industrial customers.[46]

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44 Note that U.S. Federal Regulations are now equivalent to this ballast efficiency specification.

45 These include: LED screw-in lamps, high bay LED fixtures, electrically commutated motors for evaporator fans, cold climate air source heat pump systems, and low flow pre-rinse spray valves.

46 The Industrial Energy Efficiency Program's cost effectiveness and potential energy savings will be evaluated on a year to year basis.

Customer Energy Savings

Table 10 shows forecast customer energy reduction estimates for the programs in the 2016 Plan, by sector, from 2016 through 2020.

Table 10
2016 Plan Energy Reduction Estimates
2016 through 2020
(GWh)

	2016	2017	2018	2019	2020	Total
Residential	80.4	102.7	118.1	123.5	111.7	536.4
Commercial	18.7	27.6	37.5	48.6	61.4	193.8
Industrial	30.6	30.6	30.6	30.6	30.6	153.0
Total	129.7	160.9	186.2	202.7	203.7	883.2

The programs in the 2016 Plan will result in estimated aggregate customer energy savings of approximately 883.2 GWh from 2016 through 2020. Customer energy savings are forecast to increase annually through 2020, due to expansion of the program portfolio and the addition of program technologies for the residential and commercial sectors.

Several program offerings are expected to be concluded during the planning period. These include the Small Technologies program and the Benchmarking program. Design of alternate programming for the residential sector is anticipated through the Utilities' program planning in 2018.

Demand Management

The previous conservation and demand management plans have focused primarily on energy conservation.[47] However, the Utilities' customer energy conservation programs have resulted in quantifiable demand savings.

The technologies identified through the CPS as having the most potential for demand reduction included direct load control of residential hot water tanks and curtailable load arrangements with commercial and industrial customers. Recent research has identified issues with the cost effectiveness of residential load control on the Island Interconnected System. As a result, this measure is not included in the 2016 Plan.[48] The Utilities will continue to pursue curtailment opportunities with their larger customers.[49]

A new component will also be added to the Business Efficiency Program ("BEP") to include a custom incentive for demand reduction measures that are economically viable and that provide measureable demand reduction during peak times.[50]

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[47] This reflected the relatively high marginal energy costs (predominantly due to fuel costs at Hydro's Holyrood Thermal Station) which justified such a focus.

[48] Although residential load control on the Island Interconnected System does not make economic sense, Hydro's isolated communities served by diesel generation have higher marginal costs which may make the program cost effective.

[49] Hydro currently has interruptible load arrangements with its Industrial Customers which have potential for more than 90 MW of capacity assistance. Newfoundland Power currently has 16 customers participating in its Curtailable Rate Option, providing 10.4 MW of potential load reduction.

[50] More information on the custom demand component of the BEP can be found in Schedule C.

Table 11 shows forecast customer demand reduction estimates for the customer energy conservation programs in the 2016 Plan, by sector, from 2016 through 2020.

Table 11
2016 Plan Demand Reduction Estimates
2016 through 2020[51]
(MW)

	2016	**2017**	**2018**	**2019**	**2020**	**Total**
Residential	3.3	4.7	5.0	4.3	1.4	18.6
Commercial	2.1	2.0	2.3	2.5	2.8	11.7
Total	5.4	6.7	7.3	6.8	4.2	30.3

The Utilities' takeCHARGE customer energy conservation programs are forecast to achieve approximately 30.3 MW in peak demand reduction through 2020. This demand reduction will occur annually for the life of the installed technologies.[52]

[51] Hydro does not forecast demand reduction for their transmission level industrial customers.
[52] For example, a customer who installs basement insulation in 2014 will achieve approximately 0.9 kW of annual peak demand reduction for the next 20 years.

2016 Plan Program Costs

Table 12 shows forecast costs for the programs in the 2016 Plan, by sector, from 2016 through 2020.

Table 12
2016 Plan Program Costs Estimates
2016 through 2020
($000s)

	2016	2017	2018	2019	2020	Total
Residential	5,987	6,308	4,540	3,048	2,042	21,925
Commercial	1,628	1,906	1,933	2,258	2,301	10,026
Industrial[53]	667	10	10	10	10	707
Total	8,282	8,224	6,483	5,316	4,353	32,658

The Utilities' costs related to programs in the 2016 Plan are forecast to be approximately $32.7 million over the five-year planning period. Forecast changes in program costs primarily reflect the expansion of programs and additional technology offerings anticipated from 2016 to 2018, and the conclusion of certain programs through the planning period.

3.3 Education & Support

The Utilities' customer education and support activities will continue to evolve to support changes in customer energy conservation programs and in the broader conservation market. The Utilities will continue to provide customer support and be responsive to customer expectations. Current activities, including customer outreach events, the takeCHARGE website and partnerships with industry stakeholders will be key elements of customer education.

[53] Forecasted Industrial program costs after 2016 are associated with program promotion and customer engagement. Given the small number of transmission level customers in the province, there is a high degree of uncertainty for participation in the program year to year. The forecasted amounts after 2016 will increase if customers avail of the program for feasibility assessments or incentives for energy efficiency retrofits. Projects will continue to be screened based on cost effectiveness to ensure the program remains above minimum economic thresholds.

The Utilities' educational initiatives will be expanded to include a program promoting mini-split heat pumps. The program components will include financing, education and marketing initiatives directed towards customers, and direct engagement with certified installers and suppliers. A marketing campaign will be launched to raise customer awareness of the benefits of this technology, how to choose a high quality product, as well as the necessity of having the system installed by qualified contractors. The eligibility criteria for on-bill financing of these systems will encourage the installation of high efficiency units, installed by qualified contractors.[54]

The Utilities will continue to build upon their experience offering the takeCHARGE K-I-C Start School Program. Marketing will continue to build awareness of the program amongst school boards and teachers. Teaching aids will be developed and be made available on the takeCHARGE website to assist in furthering conservation education after presentations are conducted. Updates will also be made to strengthen the message of conservation for younger students, and awareness-building contests will be offered for all age groups.

Table 13 shows forecast costs for conservation education and support for the period 2016 to 2020.

Table 13
Conservation Education & Support
Costs 2016 through 2020
($000s)

	2016	2017	2018	2019	2020	Total
Education	770	791	827	851	873	4,112
Support	171	175	181	184	191	902
Total	941	966	1,008	1,035	1,064	5,014

[54] Financing has been offered by Newfoundland Power since the 1990s and Hydro will have financing available beginning in 2016.

3.4 Planning & Evaluation

Planning

The 2016 Plan incorporates research and analysis required for the next iteration of multi-year conservation portfolio planning by the Utilities.

Table 14 shows forecast planning costs included in the 2016 Plan.

Table 14
Conservation Planning Costs 2016-2020(F)
($000s)

	2016	2017	2018	2019	2020	Total
Planning	527	596	767	863	644	3,397

Variability in annual planning costs reflects the Utilities' multi-year planning cycle for customer conservation programs.

The Utilities anticipate development of the next multi-year plan for customer energy and demand conservation programming in 2018. Further clarity regarding electrical system cost dynamics is expected to be a factor in the next planning cycle.[55] Further assessment and adjustments to the programming contained in the 2016 Plan may also be required within the next three years as marginal cost forecasts are updated.

Research

The next update of the study of conservation potential in the province is being planned for 2020. In advance of this study, the Utilities will undertake a number of research projects regarding electricity end-use trends and the state of the local market for efficient technologies. For the residential sector, customer surveys will gather details on

[55] An updated marginal cost study is expected to be a key input to the next conservation plan in 2018 and the next CPS in 2019-2020.

the type of electrical equipment that customers have in their homes, as well as their energy-related behaviour and motivation. Research for the commercial sector will include on-site facility audits to collect data on mechanical and electrical equipment being used.

The residential lighting market will be evaluated in 2017 to determine whether the Small Technologies program should continue. This research is expected to include a socket saturation study, with onsite inventories, as well as customer surveying. This will provide the Utilities with detailed data regarding the remaining potential for energy efficient lighting replacements.

Hydro is currently investigating the implementation of an Isolated System Direct Load Control Pilot in the community of Postville, Labrador.[56] The community of Postville is served by diesel generation. The objective of this pilot will be to reduce the peak load in the community and defer investment in electrical system upgrades. The Utilities will also continue to coordinate conservation planning with electrical system planning, and will evaluate potential for conservation initiatives targeted in specific areas or communities that may provide a lower-cost alternative to electrical system upgrades.

The Provincial Office of Climate Change Home Energy Monitoring Pilot Project is ongoing and the final report will be submitted to Government by end of March 2016. The results of this pilot project will be used to assess whether this type of technology may be considered as part of future energy conservation programming.

During this planning period, the Utilities will also monitor developments in North American practices for economic evaluation and screening of conservation programs.[57]

[56] The pilot will involve commercial and residential customers. It will include installing load controllers on hot water tanks, and commercial electric heating circuits, for commercial customers. Load controllers will only be activated during maximum system peak events. The customers that participate will receive incentives such as credits at the local store in Postville.

[57] While reliance on the TRC and PAC tests for primary economic screening is currently the norm in North American jurisdictions, modifications to the TRC methodology are being considered in a number of cases. These modifications primarily involve inclusion of customers' non-energy benefits from efficiency upgrade projects.

Evaluation

The customer program portfolio will continue to be evaluated in terms of its energy savings, market impacts and delivery process effectiveness. Additional review by third party evaluators is expected, reflecting the expanded program portfolio and delivery methods.[58] Program evaluation findings will be used to refine program design and implementation details on an ongoing basis, as well as support further planning.

Specific evaluation objectives in the 2016 Plan are to monitor market saturation of particular technologies as well as cost effectiveness of the programs. For example, the Instant Rebates component of the Small Technologies program will be evaluated and an exit strategy designed based on research into the pace and impact of LED sales growth in the local lighting market.

Similarly, the Utilities will continue to closely monitor the Insulation, Thermostat and HRV programs. These programs have unique challenges and barriers to program participation.[59] Evaluation of these programs will ensure they continue to satisfy cost effectiveness requirements.

In the case of new program introductions, post-implementation evaluations will be conducted within 12 months of program launch to ensure full assessment of program design assumptions, as well as marketing and delivery process effectiveness.

[58] Evaluation costs are primarily reflected in the costs for each specific program.

[59] For the Insulation and Thermostat Programs, these barriers primarily reflect the inherent difficulty in renovating existing living spaces and the remaining market being increasingly hard-to-reach. For the HRV program, this reflects the low level of customer understanding and slow adoption by the supply chain.

3.5 Costs & Cost Recovery

Table 15 provides a summary of the Utilities' customer energy conservation program and general costs from 2016 through 2020.[60]

Table 15
Conservation Costs
2016 through 2020
($000s)

	2016	**2017**	**2018**	**2019**	**2020**
Program					
Residential	5,987	6,308	4,540	3,048	2,042
Commercial	1,628	1,906	1,933	2,258	2,301
Industrial	667	10	10	10	10
Total Programs	8,282	8,224	6,483	5,316	4,353
Education	770	791	827	851	873
Support	171	175	181	184	191
Planning	527	596	767	863	644
Total General Costs	1,468	1,562	1,775	1,898	1,708
Total	9,750	9,786	8,257	7,214	6,061

Costs related to the customer energy conservation programs outlined in the 2016 Plan are forecast to be $9.8 million in 2016 and 2017.[61] This increase primarily reflects the addition of a new program, and enhanced program technology offerings. Costs begin to decrease in 2018 from $8.3 million to $6.0 million in 2020. This decrease primarily reflects the conclusion of the Small Technologies program in 2018 and the conclusion of the Benchmarking program in 2019.

60 This cost summary does not include costs related to Newfoundland Power's demand management activities (Curtailable Service Rate Option and facilities management) and costs related to Hydro's interruptible load arrangements.

61 All customer energy conservation programs outlined in the 2016 Plan are cost effective, and are justified on a cost of service basis.

Schedule E provides a summary of forecast energy savings, cost estimates and cost effectiveness analysis results for the programs in the 2016 Plan.[62]

Cost Recovery

The Utilities propose conservation cost recovery based on amortizing customer energy conservation program costs over seven years.[63] The amortization of program costs over a seven-year period is considered appropriate because of the extended nature of the energy savings benefits provided by program technologies.

The Utilities' annually recurring general conservation costs would continue to be expensed as incurred.[64]

4.0 OUTLOOK

The Utilities anticipate significant changes in the electrical system serving the province within the five years considered in this plan. The Muskrat Falls hydroelectric development and related interconnection to the North American grid will affect system operations and costs, as well as customer prices. The next iteration of multi-year conservation program planning is anticipated in 2018, to coincide with these events.

In the interim, the approach outlined in the 2016 Plan will remain flexible to address ongoing changes. The initiatives in the 2016 Plan are cost effective based on current information, and were assessed for sensitivity to changes in system costs. As the Utilities implement the program changes outlined in this Plan, they will continue to evaluate program offerings to ensure they create economic benefits and are responsive to evolving customer expectations and market conditions.

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62 Cost forecasts can be expected to be refined as detailed program design progresses in 2016.

63 Newfoundland Power has used this approach since 2013, based on Order No. P.U. 13 (2013). Hydro has proposed this approach in its ongoing general rate application, and the proposal has been agreed to by the parties to settlement negotiations in that matter.

64 While general customer energy conservation costs provide benefits to customers in terms of information, knowhow and advice, those benefits are not transparently quantifiable in the same manner as program benefits.

With growing customer awareness of conservation, and of the takeCHARGE brand, the Utilities will continue to seek opportunities to partner with complementary organizations and trade allies for customers' advantage. Information sharing and policy coordination with the Province will also continue, primarily through the Office of Climate Change and Energy Efficiency.

Table A-1 shows most recent marginal cost forecast as projected by Newfoundland and Labrador Hydro in February 2015.

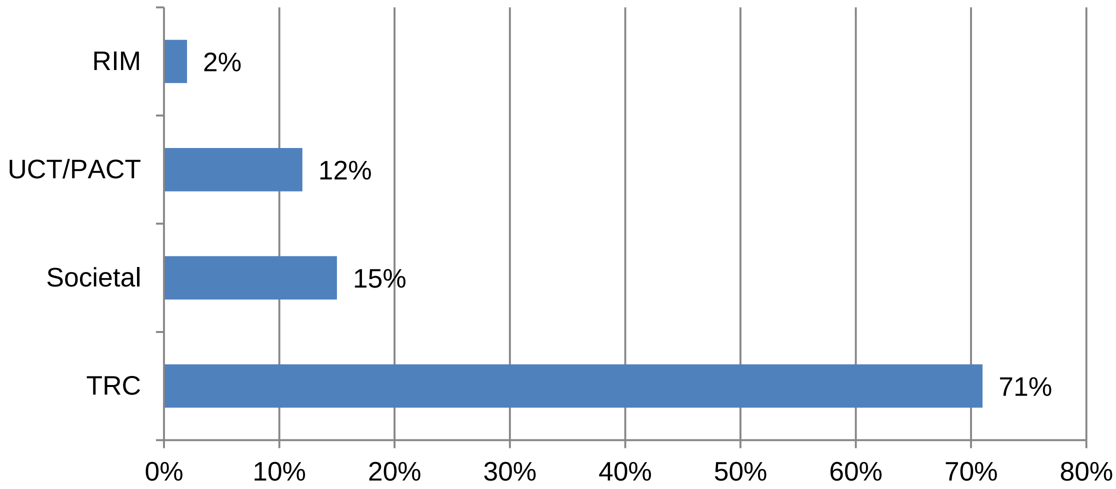
Table A-1 Marginal Cost Projection for the Island Interconnected System 2015 - 2035		
	Energy ($/MWh)	**Capacity ($/KW – Yr)**
2015	108	51
2016	133	70
2017	134	74
2018	47	98
2019	50	99
2020	54	108
2021	56	112
2022	59	115
2023	62	119
2024	65	123
2025	68	126
2026	70	126
2027	73	125
2028	76	125
2029	78	124
2030	81	124
2031	85	121
2032	88	118
2033	92	116
2034	96	113
2035	100	110

Notes:
1. Modeled as per NERA Economic Consulting marginal cost approach (2006).
2. Fuel costs per NLH corporate assumptions, January 2015.
3. Excludes transmission marginal costs.
4. Projection is at customer bulk delivery point.
5. Island Interconnected costs beyond 2017 reflect opportunity cost as per NERA approach.

Table B-1 Current Canadian Utility Practice Economic Evaluation Practices					
Province	**Economic Test**				
	TRC	PAC	RIM	PCT[1]	SCT[2]
British Columbia	X[3]				
Ontario	X	X			
Nova Scotia	X	X			
Manitoba[4]	X		X	X	X
Saskatchewan	X	X			
Quebec	X		X[5]		
Prince Edward Island	X	X[6]		X	X[6]

1 Participant Cost Test ("PCT").
2 Societal Cost Test ("SCT").
3 British Columbia uses a modified TRC that includes non-energy benefits that are not traditionally included in the TRC.
4 Manitoba also considers the levelized resource cost, net utility benefit, utility net present value, levelized utility cost, and simple customer payback calculation.
5 Quebec considers the RIM as a secondary test.
6 Prince Edward Island considers the PAC and SCT as secondary tests.

Chart B-1
Current American Utility Practice
Economic Evaluation Practices
(Percent of States)



[7]

n=43

[7] Research conducted by the American Council for an Energy Efficient Economy (February 2012) "A National Survey of State Policies and Practices for the Evaluation of Ratepayer-Funded Energy Efficiency Programs".

Insulation Program

Program Description
The objective of this program is to increase the insulation level in residential basements, crawl spaces and attics. Increasing the insulation R-value in a home will result in space heating energy savings. The program components include rebates and financing, and a variety of education and marketing tools. This program has been offered through takeCHARGE since 2009.
Target Market: Residential
This program targets residential customers completing retrofit projects. Changes to the National Building Code of Canada implemented in December 2012 mandated that all new homes install basement insulation and increased the R-Value requirements in the attic. As a result, this program is only offered to existing homes (i.e. connected to the electricity grid before January 1, 2014) to exclude minimum building code compliance in new homes. Eligibility will continue to be limited to electrically-heated homes.
Eligible Measures
Eligible measures in this program include insulation upgrades to basements, crawl spaces and attics. Technical requirements will be approximately aligned with National Building Code of Canada.
Delivery Strategy
Delivery of this program will continue to be bundled with Thermostat, Instant Rebates, Appliance & Electronics and HRV programs as part of the takeCHARGE residential portfolio. Marketing initiatives include partnering with retailers and trade allies in the renovation industry, and target both do-it-yourself and professional installers. Tools and tactics will include retail point-of-sale materials, advertising, website, tradeshows, community outreach and trade ally activities. Rebates and financing will be processed through mail and online customer applications.

Insulation Program

Market Considerations
Barriers to increased market penetration include initial cost, awareness of the impact on space heating energy, the practical difficulties of renovating an existing living space and a decreasing number of eligible participants. Experience with the existing program has shown participation to be responsive to awareness-building marketing activities.
Incentive Strategy
Incentives for this program include rebates and financing. In August 2014, the rebate structure was simplified and increased. Customers can now get a rebate of 75% of the cost of materials installed in the basement and 50% of the cost of materials in the attic. Rebates amounts are capped at $1,000.
Program Monitoring & Evaluation
The program will be monitored for participation level, service quality, market saturation and cost effectiveness. A representative sample of installations will be inspected. Formal external evaluations will be conducted every two years during operation.
Estimated Costs & Energy Savings

	2016	**2017**	**2018**	**2019**	**2020**	**Total**
Estimated Costs ($000s)	1,187	1,207	1,202	1,197	1,223	6,018
Estimated Cumulative Energy Savings (GWh)	30.0	33.1	36.1	38.9	41.8	180
Total Resource Cost						**2.5**

Thermostat Program

Program Description

The objective of this program is to encourage installation of programmable and high performance electronic thermostats in homes. Programmable and high performance electronic thermostats allow customers to better control the temperature of their homes and to set back the temperature during the night or while away. The program components consist of rebates, financing options, and a variety of education and marketing tools. This program has been offered through takeCHARGE since 2009.

Target Market: Residential

This program targets residential customers, including home retrofit and new home construction. Eligibility will continue to be limited to electrically-heated homes.

Eligible Measures

Eligible measures in this program include both programmable and high performance electronic thermostats. All thermostats must have a setting precision of +/- 0.5 degrees Celsius or less.

Delivery Strategy

The delivery strategy for this program remains unchanged. Delivery of this program will continue to be bundled with the Insulation, Instant Rebates, Appliance & Electronics and HRV programs as part of the takeCHARGE residential portfolio.

Marketing initiatives include partnering with retailers, electrical contractors, homebuilders and real estate professionals, to educate consumers regarding the energy savings and comfort benefits of programmable & high performance electronic thermostats. Tools and tactics include retail and model home point-of-sale materials, website, tradeshows, community outreach and trade ally activities. Rebates will be processed through mail and online customer applications.

Thermostat Program

Market Considerations

Barriers to installation of programmable and high performance electronic thermostats include lack of awareness of the potential for energy savings, difficulty programming, and reluctance to pay for an electrician to install the thermostats, and a decreasing number of eligible participants.

Incentive Strategy

Incentives for this program include rebates and financing. The rebate value is $5 per high performance electronic thermostat and $10 per programmable thermostat. This continues to reflect incremental cost of the more efficient options. A time limit is no longer required for incentive redemption.

Program Monitoring & Evaluation

The program will be monitored for participation level, service quality, market saturation, and cost effectiveness, and a representative sample of installations will be inspected. Formal evaluations will be conducted every two years during program operation.

Estimated Costs & Energy Savings

	2016	**2017**	**2018**	**2019**	**2020**	**Total**
Estimated Costs ($000s)	517	555	539	557	552	2,720
Estimated Cumulative Energy Savings (GWh)	9.7	11.1	12.5	13.8	15.2	62
Total Resource Cost						**2.8**

Small Technologies Program

Program Description
The objective of this program is to increase home energy efficiency and awareness by offering instant rebates on a variety of energy efficient technologies as well as online and mail in rebates for eligible appliances and electronics. This program also includes promotional events to raise awareness of the technologies and to engage the public.
Target Market: Residential
This program is marketed toward all residential customers province wide. All customers are eligible to participate regardless of age of home or heat source. A variety of marketing techniques such as TV news sponsorships, print, radio, online, website, as well as social media channels are used to engage customers.
Eligible Measures
Eligible measures in this program will vary over time and will be selected based on cost effectiveness, energy saving potential and market conditions. Instant rebates are available for small energy efficient items such as LEDs and smart power bars, and online and mail in customer applications are required for qualifying models of full-size refrigerators, clothes washers, TVs and full-size Energy Star freezers. Six new measures will be added to the technology list in 2016. They are: • Faucet aerators • Door bottom weather stripping • Door adhesive • Window insulation kit • Electrical outlet gaskets • Caulking

Small Technologies Program

Delivery Strategy
Partnerships have been made with both chain and independent retailers to offer instant rebates to customers on a number of energy efficient products. Efforts to engage both urban and rural retailers have been made in order to ensure rebated products are available in all areas of the province. Campaigns are held in the spring and fall each year. During each campaign, the Utilities set up in-store events at the participating locations to raise customer’s awareness of the rebates and encourage use of energy efficient products.
Market Considerations
The technologies included in the program do not involve a major renovation. This program will allow the Utilities to reach customers that may not have been able to participate in the other incentive programs.
Incentive Strategy
Incentives for this program include instant rebates for small energy efficient items that will vary by year and campaign. Online and mail in customer applications are available for eligible appliances and electronics. The rebate value will be different for each technology offered, and will reflect incremental cost of the more efficient options.
Program Monitoring & Evaluation
The program will be monitored for participation level, service quality, and cost effectiveness. Exit interviews will be conducted during selected retail events. Formal evaluations will be conducted after the first year of implementation, and biannually during operation. It is anticipated that this program will end after 2018. The Utilities expect that LEDs will make up the majority of bulbs that are sold in the province. If this occurs, the economics of the program will no longer be cost effective. The uptake of LEDs will be monitored and evaluated to confirm the market saturation rate in 2017.

Small Technologies Program

Estimated Costs & Energy Savings						
	2016	**2017**	**2018**	**2019**	**2020**	**Total**
Estimated Costs ($000s)	3,113	2,879	1,578	-	-	7,570
Estimated Cumulative Energy Savings (GWh)	23.8	33.3	38.2	37.4	36.5	169
Total Resource Cost						**1.3**

HRV Program

Program Description
The objective of this program is to increase the installation of higher efficiency Heat Recovery Ventilators ("HRV"). The program components include rebates and financing, and a variety of education and marketing tools.
Target Market
This program targets all residential customers regardless of heat source or age of home. Eligibility is available to all homes that install or replace an HRV.
Eligible Measures
Eligible measures in this program include all HRV models that have an SRE of 70% or more and meet the minimum fan efficacy requirements.
Delivery Strategy
Delivery of this program will be bundled with other takeCHARGE residential programs as part of the overall portfolio. Marketing initiatives include partnering with trade allies in the home building and renovation industry, particularly Heating Refrigeration and Air conditioning Institute certified installers. Tools and tactics include website presence, tradeshows, and trade ally activities. Rebates and financing will be processed through customer application.
Market Considerations
The market includes new construction and existing HRV replacement with an emphasis on existing replacements. Early HRV installations of the 1990s are at or near the end of their useful life, so many of these require replacement. This program has faced a number of barriers such as understanding of what a HRV is and its purpose in the home, initial cost, and awareness of the benefits of selecting more efficient HRVs.

HRV Program

Incentive Strategy

Incentives for this program include rebates and financing. The rebate value is $175 for qualifying HRV units. This reflects the incremental cost of the more efficient options.

Program Monitoring & Evaluation

The program will be monitored for participation level, service quality, and cost effectiveness. This program has experienced challenging barriers to program participation. Attempting to overcome these barriers can be administratively costly and may outweigh the benefits of program delivery. This program will be monitored to ensure that the participation goals are being met in each year to ensure the program remains cost effective. A representative sample of installations will be inspected. Formal evaluations will be conducted every two years during operation.

Estimated Costs & Energy Savings

	2016	2017	2018	2019	2020	Total
Estimated Costs ($000s)	223	218	232	231	267	1,171
Estimated Cumulative Energy Savings (GWh)	0.7	1.0	1.3	1.6	2.0	7
Total Resource Cost						**1.3**

Benchmarking Program

Program Description
Energy social benchmarking is the analysis of a household's energy consumption and the comparison of its performance with its energy history and that of other similar households. Historic consumption information, tracking over time and comparisons with other households can encourage customers to reduce energy consumption. A printed paper report is delivered to participating customers via mail. These reports include a normative comparison that compares the customer to similar neighbors. The printed Home Energy Report is supplemented by access to an online web portal allowing for increased customer energy usage information and tips and resources to facilitate energy use reduction.
Target Market: Residential
The Benchmarking program is marketed to residential customers across the province. Customers will be selected into the program and can withdraw (opt-out) at any time.
Eligible Measures
A home's energy use is compared anonymously to the usage patterns of other homes in the vicinity that are of similar size, age, heating type, etc. The Home Energy Report is designed to provide new information to help home owners understand their energy use and find ways to make the home more efficient.
Delivery Strategy
The program is delivered largely by a third party service provider that develops and issues the Home Energy Report and maintains the online web portal. takeCHARGE will oversee all aspects of the program to ensure greater customer insight into their home energy use. The program is available year round and will be supported with takeCHARGE marketing and communication efforts.

Benchmarking Program

Market Considerations

This program will allow the Utilities to reach customers that have not been able to participate in the other incentive programs. It will also allow takeCHARGE actively engage with customers using direct home energy consumption information. This program also allows for the cross promotion of existing takeCHARGE rebate programs as methods to reduce household consumption and to drive participation in these programs.

Incentive Strategy

No monetary incentive will be offered. It has been demonstrated that for this type of program that using social norm comparisons drives the greatest and longest lasting changes to household energy consumption.

Program Monitoring & Evaluation

The program is monitored for participation levels, service quality and cost effectiveness. Formal evaluation will be conducted very two years during operation.

Estimated Costs & Energy Savings

	2016	2017	2018	2019	2020	Total
Estimated Costs ($000s)	530	1,034	989	1,063	-	3,616
Estimated Cumulative Energy Savings (GWh)	0.3	8.0	13.8	15.6	-	38
Total Resource Cost						**1.0**

Mini Split Heat Pump Educational Initiative

Program Description

The objective of the program is to encourage customers to choose high efficiency mini split heat pumps (MSHP), installed by qualified contractors. When installed correctly, a high efficiency MSHP will provide space heating energy savings. The program components include financing, education and marketing initiatives directed towards customers, and direct engagement of certified installers. Financing has been offered by Newfoundland Power since the 1990s and Hydro will have financing available beginning in 2016, however the eligibility criteria for MSHP will be updated to support the uptake of high efficiency units.

Target Market

This program targets residential customers. New home construction and retrofit customers with electric baseboard heat are considered to have the greatest potential for participation, however customer eligibility to participate in financing will not be limited by heating fuel, age or type of dwelling.

Eligible Measures

Financing will now be limited to MSHP with an estimated Heating Seasonal Performance Factor (HSPF) of 9.6 or higher. This is aligned with the minimum HSPF required for certification of units meeting the “ENERGY STAR® Most Efficient 2015” designation. To qualify for financing the installation must be performed by a contractor that has the necessary permits and certification to perform electrical and refrigeration work in the province.

Delivery Strategy

Delivery will be a two pronged approach including marketing to customers and engaging eligible installers.

Marketing initiatives will include information on the takeCHARGE website as well as bill inserts and mass media advertising regarding the benefits of choosing the right heat pump and installer. Installer engagement will include information sessions, contests, and maintaining relationships with qualified installers.

Financing applications will be processed through customer application via the existing customer service channels (online or by phone).

An incentive could not be offered for this program because it does not pass the economic analysis.

Mini Split Heat Pump Educational Initiative

Market Considerations

One of the biggest barriers is a lack of customer awareness and availability of certified installers in rural areas. In order to achieve significant energy savings, the unit must be appropriate for the Newfoundland climate, properly installed and operated.

Other major barriers include identifying what to look for in an installer (i.e. what certification should be required) and difficulty of customers to find qualified installers. The upfront cost of highly efficient units is also a barrier for some customers.

Program Monitoring & Evaluation

This program will be monitored for participation level, and service quality. The criteria for eligible models and installers will also be continually reviewed to ensure the program is promoting units and installers that will provide customers the highest achievable energy savings at a reasonable cost.

Estimated Costs & Energy Savings

	2016	2017	2018	2019	2020	Total
Estimated Costs ($000s)	119	100	103	102	104	529

Business Efficiency Program

Program Description

The objective of the Business Efficiency Program is to help commercial customers increase their electrical energy efficiency by providing incentives on energy efficient options for existing facilities. The program provides supports to encourage customers to implement projects customized to their own facilities.

Target Market: Commercial

This program targets business owners and property managers who have an interest in making their businesses more energy efficient. The program includes a custom project approach which appeals primarily to large commercial customers. In 2016, the program will also include rebates for specific measures, such as LED lighting, Air Source Heat Pumps and High performance T8 Lighting, which appeal to small and medium sized customers as well.

Eligible Measures

The custom stream allows customers to obtain rebates for almost any energy efficiency measures that result in electrical energy and demand savings. The program excludes alternative energy and fuel switching.

Beginning in 2016 the custom stream of the Business Efficiency Program will also include incentives for demand reduction based on the options available at the customer's facilities as well as the amount of demand they are able to reduce during peak times.

Also beginning in 2016, the existing fluorescent High Bay program and the current Commercial lighting program (including high performance T8 fluorescent lamps and LED exit signs) will become prescriptive rebates under the Business Efficiency Program.[1] Electronic ballasts will no longer be available for incentive as of 2016 because these ballasts are now considered to be the market standard.

The specific measures eligible for per unit rebates have included programmable thermostats, occupancy sensors, high performance showerheads, and LED wall packs. In 2016, LED screw-in lamps, High Bay LED fixtures, electrically commutated motors for evaporator fans, cold climate air source heat pump systems and low flow pre-rinse spray valves will be added to the prescriptive list of incentives.

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[1] Prescriptive incentive program are customer energy conservation programs that have per unit rebates for installing certain defined technologies. For example, providing a predefined rebate amount for a LED light bulb;

Business Efficiency Program

Delivery Strategy

The delivery strategy for this program is mainly through individual customer interactions. A walk through audit can help customers identify efficiency opportunities.

Marketing for this program includes partnering with lighting manufacturers, distributors, electrical contractors and lighting service providers as key market influencers and allies. The program will create business opportunities for trade allies to sell more efficient products.

The program will also target commercial property owners through direct marketing and through industry associations such as the Building Owners and Managers Association. Tools and tactics will include trade ally and business association activities, such as workshops for distributors, contractors and building operators, retail point-of-sale materials, website and advertising in trade publications. Demonstration projects will be selected from program participants.

Market Considerations

Barriers to increased market penetration include initial cost, awareness of the program and available incentives, budget & planning cycles, technical know-how, and customer time constraints.

Incentive Strategy

Incentives for this program are designed to reduce the cost barrier, attract customer attention and provide technical and financial support for energy audits and feasibility studies. The custom stream provides incentives based on project energy savings at 10 cents/kWh for first year savings or project demand savings at $100 per kW per month over the December to March period. Demand saving projects require a minimum of 50 kW savings and be sustainable over 5 years. Incentives of up to $50,000 per site help garner interest and lower customer project costs.

Incentives vary for the prescriptive measures. Rebates will be processed through mail-in and online submissions.

Program Monitoring & Evaluation

The program will be monitored for participation level, service quality, and cost. Each incented project will have a measurement and verification plan to confirm energy or demand savings achieved are consistent with incentives paid.

Business Efficiency Program

Estimated Costs & Energy Savings						
	2016	**2017**	**2018**	**2019**	**2020**	**Total**
Estimated Costs ($000s)	1,519	1,791	1,813	2,133	2,171	9,427
Estimated Cumulative Energy Savings (GWh)	18.2	26.9	36.7	47.6	60.2	190
Total Resource Cost						**2.4**

Industrial Energy Efficiency Program

Program Description
The objective of this program is to improve electrical energy efficiency in a variety of industrial processes. The program components include financial incentives based on energy savings and other supports to enable industrial facilities to identify and implement efficiency and conservation projects. This program is a custom program to respond to the unique needs of the Newfoundland and Labrador industrial market, rather than a prescriptive technology approach.
Target Market: Industrial
This program targets existing, transmission level, industrial customers served by Newfoundland and Labrador Hydro.
Eligible Measures
Eligibility of projects is based on engineering review and confirmation of estimated energy savings impact. Technologies include, but are not limited to, compressed air, pump systems, process equipment and process controls.
Delivery Strategy
The program is managed internally, with external engineering services used as required. The utility takes the role of facilitator and consultant in providing methods for industrial customers to complete project proposals and implement approved projects. This program was initially launched as a three-year pilot program in 2009, with the first project applications being submitted in 2011, and closed to new projects in 2013. The industrial pilot was reviewed in 2014 by an external party for performance; the review indicated the program matched or exceeded performance of comparable industrial CDM programs relative to the size of the industrial sector in the Newfoundland and Labrador market. The program was officially re-launched as an ongoing program in 2015, with the same structure as the pilot program.

Industrial Energy Efficiency Program

Market Considerations
This market requires a one-on-one approach to project design and delivery. The program builds on the work already completed by the industrial customers, and addresses their unique barriers to improved efficiency, which include, but are not limited to, access to capital and human resources. The lifecycle for each program transaction will be measured in months rather than weeks because of the need for review, contract development, budgeting and implementation timelines, and post-installation evaluation. This type of program requires that facilities have financial and business stability to continue operations for a time period appropriate to achieve cost effective savings.
Incentive Strategy
Incentives for this program include an initial comprehensive energy audit for the site, funding assistance for feasibility studies, and financial assistance for project implementation based on energy savings.
Program Monitoring & Evaluation
The program will be regularly monitored for participation level, service quality, and cost effectiveness, including engineering review and inspection of all projects and assessment of long-term impact on customer processes.

Industrial Energy Efficiency Program

Estimated Costs & Energy Savings[2]						
	2016	**2017**	**2018**	**2019**	**2020**	**Total**
Estimated Costs ($000s)	667	10	10	10	10	707
Estimated Cumulative Energy Savings (GWh)	30.6	30.6	30.6	30.6	30.6	153
Total Resource Cost						**1.7**

[2] While Customer audits have confirmed that there are several potential projects at Hydro's customers' sites, savings for the Industrial Energy Efficiency Program (IEEP) have only been forecasted for 2016 because there are only five transmission level industrial customers in Newfoundland and Labrador and participation depends on each company's capital budgets and focus for the year. As a result of such a small market and budget considerations, participation is extremely variable from year to year and difficult to forecast. The costs from 2017-2020 are the fixed administration costs associated with program promotion and customer engagement in the IEEP. The majority of costs are incurred after a project is submitted and passes economic screening. Projects for the Industrial EE Program will be evaluated on a yearly basis and projects with a TRC of 1.0 or greater will be completed.

Isolated Business Efficiency Program

Program Description
The objective of the Isolated Business Efficiency Program is to help commercial customers increase their electrical energy efficiency by providing incentives on energy efficient options for existing facilities. The program provides supports to encourage customers to implement projects customized to their own facilities.
Target Market: Commercial
This program targets business owners and property managers in Hydro's isolated diesel and L'Anse au Loup systems who have an interest in making their businesses more energy efficient. The program includes a custom project approach and also rebates for specific measures, such as LED lighting, Air Source Heat Pumps and High performance T8 Lighting.
Eligible Measures
The custom stream allows customers to obtain rebates for almost any energy efficiency measures that result in economical electrical energy savings. The program excludes alternative energy and fuel switching. The specific measures eligible for per unit rebates have included programmable thermostats, occupancy sensors, high performance showerheads, and LED wall packs. In 2016, LED screw-in lamps, High Bay LED fixtures, Electrically Commutated Motors for Evaporator fans, Cold climate air source heat pump systems and Low Flow Pre-rinse spray valves will be added to the prescriptive list of incentives.

Isolated Business Efficiency Program

Delivery Strategy

The delivery strategy for this program is mainly through individual customer interactions. The custom track involves a walkthrough audit and feasibility analysis to determine savings and eligible incentive. This allows for a wide range of eligible technologies and projects.

Marketing for this program includes partnering with lighting manufacturers, distributors, electrical contractors and lighting service providers as key market influencers and allies. The program will create business opportunities for trade allies to sell more efficient products.

The program will also target commercial property owners through direct marketing. Tools and tactics will include trade ally and business association activities, such as workshops for distributors, contractors and building operators, and a website. Demonstration projects will be selected from program participants.

Market Considerations

Barriers to efficiency in the commercial market include financial and human resource concerns. Incentives will assist in making energy efficiency upgrades more accessible. Human resource concerns are around awareness and knowledge of the technology options as well as time to develop the business case for retrofit projects.

The isolated systems have additional challenges with access to products and access to specific technical skill sets in the evaluation of projects and technology. Hydro's program staff will assist in addressing these gaps.

Incentive Strategy

Incentives for this program are designed to reduce the cost barrier, attract customer attention and provide technical and financial support for energy audits and feasibility studies. The custom stream provides incentives based on project energy savings at the lesser of $0.4/kWh for first year savings or 80% of eligible project costs.

Incentives vary for the prescriptive measures. Rebates will be processed through mail-in and online customer applications.

Isolated Business Efficiency Program

Program Monitoring & Evaluation

The program will be monitored for participation level, service quality, and cost. Each incented project will have a measurement and verification plan to confirm energy savings achieved are consistent with incentives paid.

Estimated Costs & Energy Savings

	2016	2017	2018	2019	2020	Total
Estimated Costs ($000s)	106	112	117	122	128	585
Estimated Cumulative Energy Savings (GWh)	0.5	0.7	0.8	1.0	1.2	4
Total Resource Cost						**1.6**

Isolated Systems Community Program

Program Description

The objective of this program is to provide a portfolio of technologies and opportunities to help residential and commercial customers in isolated diesel communities save electrical energy and to promote energy efficiency awareness.

Target Market

This program targets both residential and commercial customers in Hydro's isolated systems. This includes Isolated Diesel systems on the Island, in Labrador, and the L'Anse au Loup system.

Eligible Measures

Measures will range from efficient lighting products, hot water saving products, pipe insulation, hot water tank insulation, commercial LED exit signs, and others that may be applicable.

An Appliance Retirement program is being planned for at least one community. Old inefficient appliances will be removed from participating homes and routed for appropriate disposal. This will save energy and money for the homeowner. This component will be evaluated to determine if it is economic to develop into a broader program.

The Isolated systems T12 replacement program will take place in 2-3 Isolated communities. This project will offer, free of charge to commercial customers, the supply and install of new High Performance T8 lamps and ballasts.

Delivery Strategy

Hydro has engaged Summerhill Group to deliver this program. They are using a number of delivery strategies, including hiring and training local representatives, to engage residential and commercial customers. Direct installs will be completed, whereby the customer receives the technology in their home or business at no cost. During the direct install visit, customers also receive information on energy usage and efficiency options.

Isolated Systems Community Program

Market Considerations

Availability and awareness of energy efficient technologies continues to be an issue in rural communities and often technologies available are at a higher price than in urban markets. This program will address the barriers of availability. There is a heavy electric hot water heating penetration and opportunities exist in plug load and behavior based areas.

Commercial customers tend to be smaller businesses and as such find it challenging to find the time and resources to address energy consumption issues; this program will provide the one on one interaction needed to assist these customers. The technologies included in the program do not involve a major renovation. This program will allow the utility to reach customers that may not have been able to participate in the other incentive programs.

Following the 2015 direct install component, information collected in 2014 and 2015 will be used to plan for Isolated Systems Community programming beyond 2017. Costs and energy savings will be estimated once the technologies have been determined.

Program Monitoring & Evaluation

The program will be monitored for participation level, service quality, and cost effectiveness. A representative sample of direct installs will be surveyed for confirmation of continued installation and use. Formal evaluations will be conducted after each year of operation.

Estimated Costs & Energy Savings

	2016	**2017**	**2018**	**2019**	**2020**	**Total**
Estimated Costs ($000s)	415	415	-	-	-	830
Estimated Cumulative Energy Savings (GWh)	5.2	5.5	5.5	5.5	5.5	27
Total Resource Cost						**2.7**

Table D-1
Conservation Programs
Energy Reductions: 2012 – 2015(F)
by Sector
(GWh)

	2012	2013	2014	2015F	Total
Residential					
Insulation Program	15.8	20.6	24.0	27.0	87.4
Thermostat Program	4.5	5.8	7.0	8.4	25.7
ENERGY STAR Window Program	6.1	8.6	10.1	10.1	34.9
Coupon Program	0.3	0.3	0.3	0.3	1.2
HRV	0.0	0.0	0.2	0.4	0.6
Small Technologies	0.0	0.0	5.5	14.4	19.9
Isolated Systems Community Program	1.7	2.8	4.1	4.8	13.4
Block Heater Timer Program	-	0.3	0.3	0.3	0.9
Total Residential Portfolio	**28.4**	**38.4**	**51.5**	**65.7**	**184.0**
Commercial					
Lighting Rebate Program	3.3	3.9	5.8	6.5	19.5
BEP	-	-	0.6	4.5	5.1
Isolated Systems Business Efficiency Program	-	-	0.1	0.4	0.5
Total Commercial Portfolio	**3.3**	**3.9**	**6.5**	**11.4**	**25.1**
Industrial					
Industrial Energy Efficiency Program	3.3	3.3	25.6	25.6	57.8
Total Portfolio	**35.0**	**45.6**	**83.6**	**102.7**	**266.9**

Table D-2
Conservation Programs
Program Costs: 2012 – 2015(F)
by Sector
($000s)

	2012	2013	2014	2015F	Total
Residential					
Insulation Program	882	1,092	796	1,039	3,809
Thermostat Program	492	253	227	454	1,426
ENERGY STAR Window Program	1,173	1,634	698	7	3,512
Coupon Program	-	-	-	-	-
HRV	-	59	56	225	340
Small Technologies	-	4	1,877	2,884	4,765
Isolated Systems Community Program	858	871	615	579	2923
Block Heater Timer Program	31	8	8	-	47
Total Residential Portfolio	**3,436**	**3,921**	**4,277**	**5,188**	**16,822**
Commercial					
Lighting Rebate Program	121	128	373	790	1,412
BEP	-	112	457	532	1,101
Isolated Systems Business Efficiency Program	93	115	96	66	370
Total Commercial Portfolio	**214**	**355**	**926**	**1,388**	**2,883**
Industrial					
Industrial Energy Efficiency Program	173	89	1,244	19	1,525
Total Portfolio	**3,823**	**4,365**	**6,447**	**6,595**	**21,230**

Table E-1
Conservation Programs
Energy Reduction Estimates: 2016 – 2020
by Sector
(GWh)

	2016	2017	2018	2019	2020	Total
Residential						
Insulation Program	30.0	33.1	36.1	38.9	41.8	179.9
Thermostat Program	9.7	11.1	12.5	13.8	15.2	62.3
ENERGY STAR Window Program	10.1	10.1	10.1	10.1	10.1	50.5
Coupon Program	0.3	0.3	0.3	0.3	0.3	1.5
Isolated Systems Community Program	5.2	5.5	5.5	5.5	5.5	27.2
Small Technology Program	23.8	33.3	38.2	37.4	36.5	169.1
HRV Program	0.7	1.0	1.3	1.6	2.0	6.6
Benchmarking	0.3	8.0	13.8	15.6	-	37.7
Block Heater Timer Program	0.3	0.3	0.3	0.3	0.3	1.5
Total Residential Portfolio	**80.4**	**102.7**	**118.1**	**123.5**	**111.7**	**536.4**
Commercial						
Isolated Systems Business Efficiency Program	0.5	0.7	0.8	1.0	1.2	4.3
Business Efficiency Program	18.2	26.9	36.7	47.6	60.2	189.6
Total Commercial Portfolio	**18.7**	**27.6**	**37.5**	**48.6**	**61.4**	**193.8**
Industrial						
Industrial Energy Efficiency Program	30.6	30.6	30.6	30.6	30.6	153.0
Total Portfolio	**129.7**	**160.9**	**186.2**	**202.7**	**203.7**	**883.2**

Table E-2
Conservation Programs
Program Cost Estimates: 2016 – 2020
by Sector
($000s)

	2016	2017	2018	2019	2020	Total
Residential						
Insulation Program	1,189	1,207	1,202	1,197	1,223	6,018
Thermostat Program	517	555	539	557	552	2,720
Isolated Systems Community Program	415	415	-	-	-	830
Small Technology Program	3,113	2,879	1,578	-	-	7,570
HRV Program	223	218	232	231	267	1,171
Benchmarking Program	530	1,034	989	1,063	-	3,616
Total Residential Portfolio	**5,987**	**6,308**	**4,540**	**3,048**	**2,042**	**21,925**
Commercial						
Isolated Systems Business Efficiency Program	106	112	117	122	128	585
Business Efficiency Program	1,522	1,794	1,816	2,136	2,173	9,441
Total Commercial Portfolio	**1,628**	**1,906**	**1,933**	**2,258**	**2,301**	**10,026**
Industrial						
Industrial Energy Efficiency Program	667	10	10	10	10	707
Total Programs Portfolio	**8,282**	**8,224**	**6,483**	**5,316**	**4,353**	**32,658**

Table E-3
Conservation Programs
Total Resource Cost Test Results
by Sector

	TRC Results
Residential	
Insulation Program	2.5
Thermostat Program	2.8
Isolated Systems Community Program	2.7
Small Technology Program	1.3
HRV Program	1.3
Benchmarking	1.0
Commercial	
Isolated Systems Business Efficiency Program	1.6
Business Efficiency Program	2.4
Industrial	
Industrial Energy Efficiency Program	1.7

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November 17, 2015

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

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

Dear Ms. Blundon:

Re: Liberty Consulting Group Review - Event of March 4, 2015

Hydro has reviewed the report of the Liberty Consulting Group that Hydro received on October 26, 2015. That report was provided with regard to the events of March 4, 2015.

Hydro is taking Liberty's report under advisement. Since March 4, 2015, Hydro has changed how it responds to adverse events including how it dispatches and runs generating plants. Hydro has also implemented improved internal and external communication protocols to ensure its emergency response is robust. These changes built on the significant work done following the January 2014 outage. The company will continue to move forward with its work to improve reliability for customers.

Should the Board wish to discuss this matter further, please contact the undersigned.

Yours truly,

NEWFOUNDLAND AND LABRADOR HYDRO

Geoffrey P. Young
Senior Legal Counsel

GPY/bs

cc: Gerard Hayes – Newfoundland Power
Paul Coxworthy – Stewart McKelvey Stirling Scales
Thomas J. O'Reilly, QC – Cox & Palmer
Thomas Johnson, QC – Consumer Advocate
Danny Dumaresque

ecc: Roberta Frampton Benefiel – Grand Riverkeeper Labrador

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December 22, 2015

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

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

Dear Ms. Blundon:

Re: Liberty Consulting Group Review - Event of March 4, 2015
Final Submission

Enclosed please find the original plus 12 copies of Newfoundland and Labrador Hydro's final submission in relation to the above-noted matter.

Should you have any questions, please contact the undersigned.

Yours truly,

NEWFOUNDLAND AND LABRADOR HYDRO

Geoffrey P. Young
Senior Legal Counsel

GPY/cp

cc: Gerard Hayes – Newfoundland Power
Paul Coxworthy – Stewart McKelvey Stirling Scales
Thomas J. O'Reilly, QC – Cox & Palmer
Thomas Johnson, QC – Consumer Advocate
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Review of the Newfoundland & Labrador Hydro March 4, 2015 Voltage Event

Final Submission

December 2015

newfoundland labrador hydro
a nalcor energy company

Table of Contents

1. INTRODUCTION

On October 22, 2015 the Liberty Consulting Group ("Liberty") filed its report entitled Review of the Newfoundland and Labrador Hydro March 4, 2015 Voltage Collapse ("March 4 Report") with the Board of Commissioners of Public Utilities ("Board").

Questions arose during the recent Prudence Review Hearing arising out of the March 4 Report. In that regard, Mr. Henderson confirmed that improvement was required based on the lessons learned from the March 4, 2015 events and that Hydro was committed to that improvement.[1]

Subsequent to the Prudence Review Hearing, Hydro wrote to the Board on November 17, 2015 with respect to the March 4 Report and noted as follows:

> "Hydro is taking Liberty's report under advisement. Since March 4, 2015, Hydro has changed how it responds to adverse events including how it dispatches and runs generating plants. Hydro has also implemented improved internal and external communication protocols to ensure its emergency response is robust. These changes built on the significant work done following the January 2014 outage. The company will continue to move forward with its work to improve reliability for customers."

Following the March 4 events, Hydro provided a briefing update on March 10 (subsequently updated to April 10) and a report on April 10, 2015 to the Board dealing with the March 4 events. Hydro also provided a response to follow-up Board questions on May 15, 2015, and a Field Investigation Report for each of the Holyrood Combustion Turbine ("CT") and Holyrood Units 1 and 2 in relation to the March 4 events on July 10, 2015. Those materials provided the background to the March 4 events as well as improvements taken or planned to be reviewed by Hydro.

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[1] October 29, 2015 Transcript, page 99, lines 3-6.

The remainder of these Closing Submissions will summarize the actions taken by Hydro in response to the lessons learned from the March 4, 2015 events together with Hydro's comments in reply to the recommendations by Liberty on page 9-10 of its March 4 Report. Hydro is committed to reliable service for all its customers, in a safe and least cost manner. Hydro believes the actions detailed in this submission, as well as comments in reply to Liberty's recommendations demonstrate Hydro's commitment for reliable service to customers.

2. ACTIONS TAKEN OR PLANNED TO BE TAKEN ARISING FROM THE MARCH 4, 2015 EVENTS

Following the March 4, 2015 events Hydro has undertaken the following specific actions:

1. The undervoltage protection settings for the Come By Chance capacitor banks have been changed to a new setting of 16,000 cycles (4.4 minutes) at 50% voltage to help ensure the capacitor banks do not trip for transient disturbances or during steady-state operation where voltages are below acceptable limits.

2. Corrective action has been taken addressing the fuel control valve on the new Holyrood CT as follows:
    a. The valve set position corresponding to the required flow rate was immediately marked on the valve so that if moved, the valve could be quickly returned to the proper position;
    b. The valve was locked in position using a temporary device so that it could only be moved through the deliberate removal of this locking device. An engineered permanent locking mechanism was procured, received and will be installed when an appropriate window of time presents itself. The temporary device is appropriate to remain in place until the permanent device is installed; and
    c. A pre-start-up verification of the valve position was instituted.

3. Hydro has expanded its previously occurring daily reviews and reporting of capability and reserves to include a dedicated assessment of system conditions on the Avalon Peninsula. System reliability assessments of both the Island Interconnected System and the Avalon Peninsula are now performed daily, based on current load forecasts for the next seven days. The assessments allow for advance coordination of primary generation, standby generation, and sources of reactive support, such as capacitor banks. The daily report is prepared within Hydro's System Operations department and the changes include forecasts of the Avalon capability, the impact on the capability of the system in the event of the largest single contingency, and the Avalon reserves for the upcoming seven days. This report is used by Hydro's Energy Control Centre ("ECC") operators to understand the Avalon capability with specified assets available and under the single largest contingency. This Avalon report is also reviewed at the morning system meeting, where any required notification of alerts would also be discussed.

   If the availability of assets on the Avalon changes, Hydro will perform reliability assessments in order to determine the Avalon capability and reserves for each of the upcoming seven days. If the reserves in any day are less than the impact on the Avalon capability of the single largest contingency, plus an additional reserve of 35 MW, Hydro will communicate with Newfoundland Power at regular intervals until the Avalon reserves return to normal levels, i.e., above the threshold that requires further notification. The status updates provided to Newfoundland Power by Hydro have been revised to now include the Avalon capability and reserves forecast.

   These daily assessments are used in concert with the customer/stakeholder communication protocols utilized by Hydro. Hydro has also updated its notification protocols that result from system assessments to include the notification of the Avalon capability and reserves to Newfoundland Power. This is similar to what was already in place for the assessment and notification of Island Interconnected System capability and reserves and is referred to as T-096 "Avalon Capability and Reserves." This instruction was submitted to the Board for information on October 14, 2015. The instruction was approved internally at Hydro on June 26, 2015. Hydro notes since April 8, 2015, System Operations have been generating the Avalon capability and reserves report and sharing with Newfoundland Power.

4. Hydro worked with Newfoundland Power on the specification of an undervoltage load shedding protection system for Newfoundland Power's 66 kV transmission system that will trip feeders when voltages drop below prescribed thresholds. Such an automated scheme will help to ensure that the system operates within specified voltage limits and will prevent the consequential undesired tripping of generators. A basis of design for the undervoltage load shedding was submitted to Newfoundland Power on June 30, 2015. A final design was developed by Newfoundland Power and was accepted by Hydro on November 5, 2015. The automated scheme was implemented by late November 2015.

5. Hydro reviewed the following protection operations which occurred on March 4, 2015:
    a. the resultant trip of the Star Lake generating unit was evaluated to determine if any changes were warranted to the protection systems of that unit. It was determined that the unit tripped on overfrequency, as is appropriate for the protection of this unit;
    b. the resultant trip of Holyrood Unit 3 was reviewed and the protection is confirmed to have operated as required; and

c. The protection operation trips of transmission line TL 208 and T2 at the Vale (Long Harbour) Terminal Station were reviewed to determine whether adjustments are necessary. Hydro staff (System Operations and Protection and Control personnel) met with Vale staff to review if any actions are required as follow up from the March 4 undervoltage event. The group determined that no action is required and that protection operated as required.

6. The operating instructions relating to equipment ratings and bus limits were reviewed with the ECC operators. The need for prompt and coordinated load shedding (with Newfoundland Power) was emphasized to ensure that acceptable delivery point bus voltages are maintained under equipment outage contingencies.

7. Hydro reviewed its operating procedures and has commenced the practice of operating standby generating units (that support the Avalon) in advance of the single largest Avalon contingency, rather than starting them after the event has occurred. To support this improvement, Hydro's ECC operators are receiving daily standby generation requirement guidelines for supporting the Avalon transmission.

8. An Operator Training Simulator session was developed that simulates the events of March 4. All of Hydro's ECC operators participated in this simulator training session, where they experienced declining voltages on the Avalon power system and acted accordingly to stabilize and restore the system.

9. There is a process in place for Hydro to place a red alert banner on its main webpage advising of a system event. Following the March 4 events, Hydro has moved the banner to the center of the main webpage, immediately above the

main navigation icons. The red banner includes a link to information on the Advance Notification Levels and effective ways to conserve electricity.

10. An additional communication feature has been added to the website, which allows a pop-up display to take over the main page of the website, advising customers of a power alert. This is an added feature to ensure anyone visiting Hydro's website is made aware of a power alert in effect.

11. The "Outages" button on the front page of Hydro's website links to the distribution customer Power Outage and Emergency System. The existing system was developed for Hydro's own distribution customers and is at end of life. Hydro is currently testing the new customer facing web application which includes an outage notification component. Post successful testing, the application will be launched online.

12. The Joint Storm/Outage Communications Plan was developed with Newfoundland Power following the January 2014 supply disruptions. It is to be followed by both utilities during significant system events impacting both utilities – i.e. major weather events, system disruptions or system supply shortfalls. The plan outlines specific communication tactics, timelines, messaging, approval requirements and stakeholders.

    On March 4, 2015, all processes outlined in the plan were followed and timelines were met. However, it has become increasingly apparent that customers and other stakeholders expect information to be provided to them as quickly as possible. Therefore, in an effort to get information out to customers more expeditiously, the following changes have been made to the plan:

First, timelines have been adjusted as follows:

Communication Tactic	**Timeline in Original Plan**	**Revised Timeline**
Initial social media acknowledgement	Within 30 minutes of a Level 2 or Level 3 event.	Within 15 minutes post a holding statement. Electricity System Notifications, customer requirements and critical information (i.e., conservation tactics) posted as soon as alert level confirmed.
Media holding statement	Within one hour of a Level 3 event, for Level 2 event use discretion.	Within 30 minutes for a Level 3 event brief holding statement information can be released. For Level 2, use discretion.
Website	No specific target identified	Within 15 minutes for a confirmed Level 2 or Level 3 event post a holding statement. Electricity System Notifications, customer requirements and critical information i.e. conservation tactics posted as soon as alert level confirmed.
Internal communication	Within one hour for a confirmed Level 2 or Level 3 event if required.	Within one hour for a confirmed Level 2 or Level 3 event if required.
Media release	Within 1.5 hours of mobilizing the communication team for a Level 3 event. For a Level 2 event, use discretion.	Within one hour of mobilizing the communication team for a Level 3 event. For a Level 2 event, use discretion.
Media conference (if required)	Before end of business day for a Level 3 event. Ideal timing however is prior to noon news (11:00 am) or early afternoon.	No Change.

Communication Tactic	**Timeline in Original Plan**	**Revised Timeline**
Formal updates for prolonged events (as required) - News releases, internal updates, media conferences, social media	As new information comes in: - Media updates via interviews or media release as substantial information changes are required – use discretion. - Internal updates (as needed). - Social media/website (ongoing).	No Change.
Stakeholder relations	Minimum twice daily, AM and PM.	No Change.

Second, holding statements have been developed jointly with Newfoundland Power, which allow both utilities to post a high-level statement immediately – before all information and facts on the event are known. The approved holding statements are found as Appendix F in the updated plan. The jointly revised plan containing the above modifications was filed with the Board on November 30, 2015.

Hydro has also initiated an equipment advisory protocol. The Equipment Advisory Protocol was developed following the March 4 event and outlines both Corporate Communications and Systems Operations activities required during significant equipment outages – both generation and transmission related. The intent of issuing equipment advisories for major pieces of Island Interconnected System generation and transmission equipment is to both help customers have a better understanding of the electricity system and the work that happens on equipment, and to provide any important information when an equipment outage may increase system vulnerability. For example, in the event that an emergency repair is required on TL 202 (which is one of two lines servicing the

Avalon Peninsula) during February when load on the system is high – messaging in the advisory would include information on how to prepare for and stay safe during outages and when to expect additional updates.

13. Communications between Holyrood Operations and ECC Operations include the most likely return to service time for equipment, as well as the range of return to service times where such risk exists. This will enable greater awareness by the ECC to prepare for potential reliability issues and potentially earlier alert notifications for customer communications.

14. Follow up items from Hydro's field investigation on Unit 1's delayed return to service and the Unit 3 trip are noted below. Hydro has implemented the following improvements to operations at Holyrood:
    a. Identified and corrected improvements to instrumentation that caused issues during purging and re-gassing of all units. Also, purging and re-gassing procedures have been reviewed with Operations.
    b. The control power to electronic controls and the power to the Variable Frequency Drive (VFD) cabinet cooling fans were supplied from Station Service. This caused trips to the VFDs and subsequently the generating units themselves whenever there was a bump on the Station Service feed. During the 2015 maintenance season, the control power was switched to a UPS, battery-backed power feed and the power to the cooling fans was changed to unit service. These will provide more reliable power to the VFD fans and increase unit stability going forward.
    c. With respect to the carbon dioxide required for generator purges, Hydro investigated repairing the faulty existing carbon dioxide line, or installing a new carbon dioxide line. Both options identified significant cost items as well as work protection potentials that

restricted completing these activities in 2015. Instead, piping was modified for all three units so that a skid of carbon dioxide can be brought into the powerhouse and tied-in directly for generator purges. The modifications included installing short sections of piping, isolation valves and quick connect fittings beneath each generator to allow easy connection of a portable carbon dioxide skid. This enabled bypassing of the existing carbon dioxide supply line and permits fast and efficient purging of the generator.

3. HYDRO RESPONSE TO LIBERTY RECOMMENDATIONS

On pages 9 and 10 of its March 4 Report, Liberty makes five recommendations. Each of these is listed below with Hydro's response.

1. *Hydro should assign a team to implement a program to establish a more robust operational philosophy regarding reliability.*

Hydro views service continuity as critical to its customers. Hydro evaluates its performance with a goal of continuous improvement, and also reviews its investments to continually improve its service continuity and reliability. Hydro has enhanced its reliability foundations over the past number of years, through, for example, intensive condition assessments, and those foundations were built on through increased medium to long term capital investment planning.

This previously existing objective of service continuity was further enhanced after the March 4, 2015 interruption. These enhancements are a further step forward in Hydro's approach to maintaining a reliable system. This is especially evidenced by the system and operational changes implemented in 2015 as discussed above, such as the development of the Avalon reliability assessments and procedures and placing standby generation online in advance of the single largest contingency, as opposed to after the contingency occurs. This can result in increased supply costs when operating the system, but results in lower risk of customer impact and unserved energy in the event of a contingency.

Hydro will consider Liberty's advice and recommendations in future planning as it continues to build on the work completed in 2015 with respect to improved reliability in planning for 2016 and beyond.

2. *Hydro should enhance the skills and capabilities it brings to reliability engineering and analysis.*

Hydro notes that a number of the actions taken in 2015, and discussed previously in this submission, have internally deepened the skills and capabilities with respect to reliability engineering and analysis. An example of such an action is that Hydro has become a member of the Centre for Energy Advancement through Technological Innovation's (CEATI's) Power System Planning & Operations program. The strategic direction of this program is summarized as follows:

> …to enable the use of new technologies, including FACTS, to enhance the use of existing and new transmission facilities while continuing to maintain a high level of reliability. This includes exploring and developing tools and techniques for planning and operating transmission systems in a reliable, secure and cost-effective manner.[2]

Hydro remains committed to the development of personnel and will continue to look for opportunities for courses and training in the field of reliability. For example, Hydro has recently moved an employee with load flow capability from

[2] http://www.ceati.com/collaborative-programs/transmission-distribution/pspo-power-system-planning-operations/

System Planning into System Operations on a rotational basis. This person was replaced in System Planning with a new employee, thereby adding to the staff complement involved in reliability analyses in System Planning and System Operations.

With a continued focus on reliability, Hydro's System Operations and System Planning groups are developing initiatives that will ensure that system operators have clear direction when faced with outages to major system elements. An example of such an initiative involves developing a set of System Operating Limits for outages to system elements including 230 kV transmission lines and major generating units.

Hydro reiterates that a number of the actions taken and discussed in this submission have the effect of improving reliability engineering and analysis, with the most obvious example being the Avalon capability and reliability assessment reports that are used by numerous staff to make decisions both from an operational and communication perspective.

Hydro will consider Liberty's advice and recommendations in future planning as it continues to build on the work completed in prior to and in 2015 with respect to reliability engineering and analysis and the associated skill set within the Hydro team for 2016 and beyond.

3. *Hydro should take steps to ensure situational awareness among operators and others who need the information to respond promptly and ably to adverse system conditions.*

Hydro has an extensive training program for its operators. This includes scenarios, such as system restoration plans, or events that have occurred on the system that operators should be exposed to in a simulated environment. These planned training scenarios provide situations where the operators are required to respond rapidly and competently. This program was in place prior to March 4, 2015. In addition to the existing training scenarios, as previously discussed, Hydro developed a specific training session to simulate the rare undervoltage event that occurred on March 4, 2015 and all operators have been through this scenario.

In addition to the planned training scenarios, Hydro will communicate any operational outcomes following any major system event. This would occur upon conclusion of the review of the event. Employees would also be reminded to respond quickly and with increased urgency.

Further, in the winter season, for each weekday, Hydro has embedded senior technical System Operations personnel in the ECC in the morning period prior to peak, as well as prior to evening peak, providing additional support and oversight to operators. For weekends, Hydro assesses the system to determine if the senior technical personnel are required in the ECC for morning and evening peaks.

Hydro notes that the daily system meetings that occurred in the winter period of 2014-2015 (started in November 2014), in fact continued through spring, summer and fall of 2015 with a heightened awareness of Avalon capability. The meetings provide an opportunity to those managing and monitoring the whole system to take action as required throughout the year should any issues develop on the system.

Finally, Hydro has improved on several tools operators and others managing the system need in order to reliably manage the system. First, the spinning reserves are charted for operators to visually see spinning reserves on a real-time basis. This running chart provides operators a visual target for monitoring and feedback. This is enhanced by an audible alarm should the spinning reserve drop below the pre-set target. Another tool utilized by operators and others managing the system is a forecasted standby generation staffing and operation chart. This chart looks forward seven days and provides an indication of when Hydro should have employees at standby generation facilities, either to staff and await direction (if the reserves look adequate but are trending close to requirement for start up) or to be at the facility to place the standby generation in operation for system reliability purposes.

Hydro has taken action to provide for improved situational awareness for those involved in managing the power system. Hydro will consider Liberty's advice and recommendations in future planning and institute any additional actions deemed viable.

4. *Hydro should implement a more robust approach to the CERP.*

The existing CERP is a broad program designed to "assign specific responsibilities to individuals within Nalcor's corporate management structure as they may relate to the provision of emergency support services to entities within Nalcor during any emergency that may occur". Liberty wrote "the decision not to declare an emergency or activate its CERP reflects a culture that considers major outages "normal" and easily managed." Hydro does not agree with this statement nor does it reflect Hydro's operational philosophy. The circumstances of March 4, 2015 are on the record in this matter and the knowledge of Hydro on the morning of March 4, 2015 was that the supply to customers would be restored in a short time frame, and therefore, did not constitute an emergency necessarily requiring activation of CERP.

However, Hydro does note that the CERP is a managed document that is reviewed annually as part of the company's corporate management review process. Since March 4, 2015, it was noted that the review of the CERP document in the past has not included a person embedded in Hydro System Operations; however, the ECC and the System Operations Department are routinely consulted on all CERP process improvements. As part of the annual CERP review process, Hydro will include personnel with experience in System Operations or system response protocols. It is anticipated that this person's participation in the review will result in an improved CERP, with the aim of providing enhanced guidance to operational personnel during system events when they are required to make decisions on the activation of CERP. The addition of a System Operations or operational response person can also contribute to the discussion of Liberty's recommendation of "intermediate alerts where a full activation might not be needed".

Hydro will consider Liberty's advice and recommendations in future planning with respect to CERP.

5. *Advance notification protocols should appropriately identify potential impact in terms of the loss of power to customers.*

As previously discussed, Hydro has updated its reliability assessment and notification protocols to include the communication of the Avalon capability and reserve to Newfoundland Power, similar to what was currently in place for the assessment and notification of Island Interconnected System capability and reserve.

Hydro communicates daily with Newfoundland Power on the system reserves, and in the event the reserves are trending toward an alert level or in an alert level, will communicate more frequently as required. The content of the communication contains the MW amount of reserves, which is compared to the alert levels and required notification response, if necessary. If there is a requirement to quantify unserved energy by customer numbers in advance of shedding load, Hydro supplies the amount of MW the system could be deficient but does not supply Newfoundland Power with customer totals as Newfoundland Power has this information, and not necessarily Hydro.

If the undervoltage condition were to occur again, or an event where Hydro could quantify a MW amount to be shed, Hydro would endeavour to quantify the amount of MW to shed to regain system stability. Hydro would indicate a required MW total, and Newfoundland Power would have the estimated customer amounts to be impacted. If the undervoltage occurred rapidly, Hydro does note that the agreed to and implemented undervoltage load shedding scheme will now occur automatically, and so the ability to advise in advance would be limited, and in some situations may not possible, similar to when an underfrequency load shedding occurs and customers are not able to be provided advance notice.

Hydro and Newfoundland Power jointly reviewed and updated the Joint Communication Plan following the March 4, 2015 event. Reviews of this plan will occur as required into the future and Hydro will consider Liberty's advice and recommendations for future planning in this area where additional improvements can be viably implemented.

4. CONCLUSION

Hydro remains committed to the provision of safe, reliable and least cost supply of electricity to its customers. It has taken the lessons learned from the March 4 events, including Liberty's comments, into consideration, and has and will continue to improve its processes. Hydro fully expects the actions taken, and that Hydro will continue to take, will support Hydro's commitment to provide reliable service for all customers.

ALL OF WHICH IS RESPECTFULLY SUBMITTED.

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January 22, 2016

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

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

Dear Ms. Blundon:

Re: Newfoundland and Labrador Hydro – 2013 General Rate Application
Final Submission – Revision 1

Enclosed please find the original plus 12 copies of the revised page 46 of Newfoundland and Labrador Hydro's final submission in relation to the above-noted matter as there was a typographical error in relation to one of the numbers used.

Should you have any questions, please contact the undersigned.

Yours truly,

NEWFOUNDLAND AND LABRADOR HYDRO

Tracey Pennell

Tracey L. Pennell
Legal Counsel

TLP/bs

cc: Gerard Hayes – Newfoundland Power
Paul Coxworthy - Stewart McKelvey Stirling Scales
Thomas J. O'Reilly, Q.C. - Cox & Palmer
Dennis Browne, Q.C. – Browne Fitzgerald Morgan & Avis
Thomas Johnson, Q.C. - Consumer Advocate
Yvonne Jones, MP Labrador
Senwung Luk – Olthuis, Kleer, Townshend LLP
Genevieve M. Dawson – Benson Buffett

IN THE MATTER OF the *Electrical Power Control Act,* 1994, SNL 1994, Chapter E-5.3 (the "*EPCA*") and the *Public Utilities Act*, RSNL, 1990, Chapter P-47 (the "*Act*"), as amended, and Regulations thereunder; and

IN THE MATTER OF a general rate application filed by Newfoundland and Labrador Hydro on July 30, 2013; and

IN THE MATTER OF an amended general rate Application filed by Newfoundland and Labrador Hydro on November 10, 2014; and

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Newfoundland and Labrador Hydro

2013 General Rate Application
Closing Submissions

December 23, 2015

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Table of Contents

A. DEFINED TERMS

The following terms appear in either the GRA Submission or the Prudence Review Submission and are as defined below.

Term	**Definition**
Act	*Public Utilities Act,* SNL 1990, Chapter P-47 (as amended)
Admin Fee	Administration Fee
Amended Application	Hydro's Amended Application, filed on November 10, 2014
ATCO	*ATCO Gas and Pipelines Ltd. v. Alberta (Utilities Commission)*, 2015 SCC 45
bbl	Barrel
BCUC	British Columbia Utilities Commission
Board	Public Utilities Board (NL)
BTU	British Thermal Unit
CBPP	Corner Brook Pulp and Paper
CDM	Conservation and Demand Management
CF(L) Co	Churchill Falls (Labrador) Corporation Limited
CIAC	Contribution in Aid of Construction
COS	Cost of Service
Cost Deferral Application	*Cost Deferral Application*, filed by Hydro on July 10, 2015 (as subsequently amended)
CPP	Canada Pension Plan
CT	Combustion Turbine
CT Application	*Application, Supply & Install of 100MW Combustion Turbine Generator*, filed by Hydro on April 10, 2014

Term	**Definition**
Deloitte	Deloitte Canada
EFB	Employee Future Benefits
EI	Employment Insurance
EPC	Engineering, Procurement and Construction
EPCA	*Electrical Power Control Act, 1994*, SNL 1994, Chapter E-5.1 (as amended)
Exploits	Exploits Generation
FTE	Full Time Equivalent
GHG	Greenhouse Gas
Government	Government of Newfoundland and Labrador
GRA	*General Rate Application*, filed by Hydro on July 30, 2013 (as subsequently amended)
GWh	Gigawatt hours
HTGS	Holyrood Thermal Generating Station
Hydro	Newfoundland and Labrador Hydro
Hydro Reply Evidence	Hydro's Reply Evidence on the Prudence Review, filed by Hydro on August 7, 2015
Ibid.	Provides a footnote reference that was cited in the preceding footnote
IIC	Island Industrial Customer
IIS	Island Interconnected System
IS	Information Systems
ITC Guidelines	Intercompany Transaction Costing Guidelines
KPI	Key Performance Indicators

Term	**Definition**
kV	Kilovolt
kW	Kilowatt
kWh	Kilowatt Hour
La Capra	La Capra and Associates Inc. (currently Daymark Energy Advisors)
Labrador Towns	Labrador Towns, consisting of Labrador City, Wabush, Happy Valley-Goose Bay and North West River
Liberty	Liberty Consulting Inc.
Liberty Final Report	Liberty's Final Report in the Prudence Review, filed by Liberty on July 7, 2015
Liberty Reply Evidence	Liberty's Reply Evidence in the Prudence Review, filed by Liberty on September 17, 2015
LIS	Labrador Interconnected System
LOLH	Loss of Load Hours
MWh	Megawatt Hours
Nalcor	Nalcor Energy Inc.
NARL	North Atlantic Refinery Limited
NP	Newfoundland Power
NSP	Nova Scotia Power Inc.
O&M	Operating and Maintenance
OEB	*Ontario (Energy Board) v. Ontario Power Generation Inc.*, 2015 SCC 44
OEM	Original Equipment Manufacturer
Outage Inquiry	*Investigation and Hearing into Supply Issues and Power Outages on the Island Interconnected System*

Term	**Definition**
Parties	Hydro and GRA intervenors
PM	Preventative Maintenance
Prudence Review	*Newfoundland Labrador Hydro Prudence Review*
PSPP	Public Service Pension Plan
RFI	Request for Information
ROE	Return on Equity
RSP	Rate Stabilization Plan
RTV	Room Temperature Vulcanization
SEM	System Equipment Maintenance
Settlement Agreement	Settlement Agreement among the Parties, filed with the Board on August 14, 2015
Supplemental Settlement Agreement	Supplemental Settlement Agreement among the Parties, filed with the Board on September 28, 2015
Teck	Teck Resources Limited
TwinCo	Twin Falls Power Corporation Limited
UARB	Utility and Review Board
Vale	Vale Newfoundland and Labrador
WACC	Weighted Average Cost of Capital

B. BACKGROUND

Hydro's last GRA was filed on August 6, 2006, resulting in a final Order issued on April 12, 2007.[1] Since then much has changed and much has been accomplished. In particular, Nalcor was incorporated, Hydro became Nalcor's subsidiary and a number of additional Nalcor subsidiaries have since been incorporated. In addition, the Muskrat Falls hydroelectric project, including the Labrador-Island Link and Maritime Link, has since been sanctioned and construction of these projects is well underway.

Corporate restructuring did not change the fundamental nature of Hydro's business, nor did restructuring change Hydro's mandate to generate, transmit and distribute safe and reliable power and energy to its customers at least cost. Instead, restructuring provided new opportunities for Hydro to benefit its customers by sharing services with its affiliates. To take advantage of these opportunities, Hydro adopted a matrix organizational model, resulting in both savings and efficiencies in the way Hydro operates its business.

As noted by Mr. Young, counsel for Hydro, in his opening remarks:

> *Hydro's duty as an electrical utility is to provide safe and reliable service to its customers at reasonable cost. The purpose of this General Rate Application is to provide Hydro with electricity rates that will provide the necessary revenue to carry out that duty. Those rates must provide Hydro with sufficient revenues to ensure its reasonable expenses can be paid and must provide Hydro with sufficient margin so that Hydro can access debt in the marketplace on reasonable terms.*[2]

[1] Order No. P.U. 8(2007).
[2] September 9, 2015 Transcript, pages 12-13.

Despite various challenges faced by Hydro in responding to the system interruptions in January 2013 and 2014, Hydro has accomplished much since the last GRA. This was highlighted by Mr. Martin, CEO in his direct evidence:

> *New generation would be required with supporting infrastructure. So throughout the decision process, a decision was made to address this need through the combustion turbine that was recently pushed into service and the Muskrat Falls Labrador Island Link Project. These projects were sanctioned, and as I mentioned, they're either in service with respect to the new combustion turbine or they're under construction as we speak with Muskrat Falls and the Labrador Island Link.*
>
> *We have accomplished these efforts and initiatives which are required in the context of safety performance significantly improving over that same period of time. Last year for the first time in Newfoundland and Labrador Hydro's history, there was zero lost time incidents. From an environmental performance perspective, Holyrood emissions have been significantly reduced in respect to the sulphur dioxide NOx and particulate. GHG is still the same issue it was in the past, needs to be dealt with. Now in addition to that with respect to our ISO 14001 certification, we've increased our record of meeting our annual targets from an average of 75 percent to now we are sustained meeting those targets in between a 98 to 100 percent level each year.*
>
> *The key reliability indicators for direct customer service have stabilized. We are focused there on measures maintaining the ability to supply the customer. I offer, for example, some of the key performance measures that we are tracking. With respect to the bulk transmissions system, we're looking at the 230 kV system in two parts. Part A, the transformer and circuit breaker performance, we are outperforming the Canadian average, and on the 230 kV transmission system,*

> *we're generally aligned with the CEA averages, more volatility, but over time aligned.*[3]

As has been discussed in the hearing, Hydro has experienced growth in operating expenses since 2007. Demand growth and the requirement for new generation, coupled with aging assets requiring significant reinvestment have put pressure on Hydro's earnings. As Mr. Martin testified:

> *Our next step was evident. We took a step back, established the condition based assessment for all of the assets, we developed a comprehensive 20 year outlook for each of those assets, we prepared an initial budget and a schedule against this plan over a 20 year period, we then stood back and resourced the plan understanding what level of resources would be required to carry it out, we optimized that resource levelling, and we established the plan and locked it in place. This plan has yielded an outlook which has more than doubled our capital expenditures for sustaining capital from 2005 of approximately 35 million. We've more than doubled that per year and that will continue over time. It's an absolutely [sic] requirement to maintain these assets and keep them at a point where they offer acceptable reliability to the customer.*
>
> *In addition to additional capital, regular annual maintenance work is increasing, it has to increase, the assets need it. The increase in ongoing maintenance costs will continue to increase as these assets continue to age and we seek to maintain their reliability.*[4]

Hydro continually balances reliability and least cost in fulfilling its mandate to provide safe, least cost, reliable service. Hydro respectfully submits that it has exercised due care in the

[3] September 9, 2015 Transcript, pages 59-60.
[4] September 9, 2015 Transcript, pages 58-59.

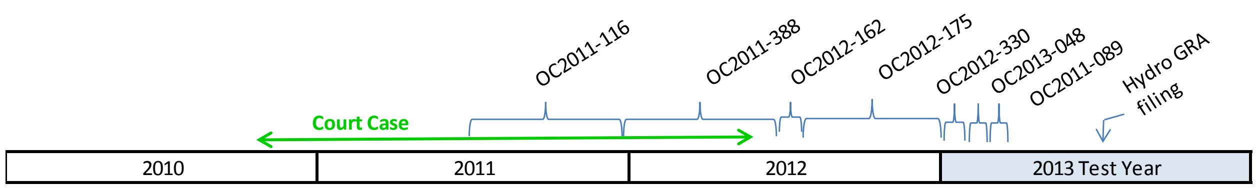
management of costs, but the reality of its infrastructure needs necessitates asking for the relief sought at this time.

B.1 PROCEDURAL HISTORY

B.1.1 Timing of GRA Filing

Hydro's GRA filing on July 30, 2013 resulted in a period of almost seven years since its previous filing on August 3, 2006.[5] Hydro believes that a period of three years is an appropriate period between GRA filings.[6] The delay in the GRA filing is recounted in Hydro's response to NP-NLH-369[7] and depicted graphically in Chart 1 below.

Chart 1



There were developments materially affecting Hydro's load, costs and revenues, commencing in 2007 with the closure of a paper machine in Corner Brook and followed by the closure of the Grand Falls paper mill announced in late 2008 and carried out in 2009, that made filing a GRA in that timeframe problematic. Due to the operation of the RSP and the potential rate volatility for the IICs, on January 16, 2009, Hydro applied to the Board for an Order to extend the deadline for filing a GRA until June 30, 2009 and to continue the existing IIC rates. In response, the Board issued an order approving the continuation of the rates, rules and regulations for the IICs on an interim basis, and directing Hydro to make an application to finalize the interim rates, rules and regulations by June 30, 2009.[8]

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[5] For a more thorough account of these matters, please see Hydro's response to NP-NLH-369.
[6] PUB-NLH-074 and PUB-NLH-075.
[7] NP-NLH-369, page 3, line 8 to page 5, line 10.
[8] Order No. P.U. 6(2009).

Hydro filed an Application on June 30, 2009, in which it did not seek changes to the RSP rates. Hydro stated "…that application of the existing RSP rules to calculate rates for Industrial Customers would result in significant and unreasonable rate volatility...". Notice of the Application and the hearing date were published, interventions were filed and over several months, RFIs were issued and answered.

The Board held a hearing on June 14, 2010 to consider issues pertaining to the Board's jurisdiction with regard to that matter. The Board found that its jurisdiction with regard to some of the issues was limited.[9] On September 17, 2010, Hydro and the Consumer Advocate appealed this decision to the Court of Appeal, arguing that the Board did have jurisdiction over the RSP amounts. The appeal on the matter of the Board's decision was heard in December of 2010; a decision on the appeal was rendered by the Court in June of 2012, reversing the Board's decision.

Notwithstanding that some issues remained unresolved and were before the Court, in late 2010, the Board took steps to recommence and resolve the outstanding IIC rates and RSP matters. These processes were underway when the Lieutenant Governor in Council directed the Board to defer consideration of these matters and directing Hydro to file a GRA by December 31, 2011.[10] A subsequent Government directive delayed the GRA filing until June 30, 2012.[11]

Following the Court of Appeal decision in June 2012, a series of Government directives further changed the GRA filing date:

- OC2012-162 delayed the GRA filing until July 16, 2012;
- OC2012-175 delayed the GRA filing until December 31, 2012;
- OC2012-330 delayed the GRA filing until February 28, 2013;
- OC2013-048 delayed the GRA filing until March 31, 2013;

[9] Order No. P.U. 25(2010).
[10] OC2011-116.
[11] OC2011-388.

- OC2013-083 delayed the GRA filing until April 15, 2013; and
- OC2013-089, OC2013-090 and OC2013-091 dated April 4, 2013, which resulted in Hydro's eventual GRA filing on July 30, 2013.[12]

References have been made during the GRA proceeding to Hydro's responsibility for the delay in filing its GRA. Hydro points out that the initial directive, OC2011-116 dated April 19, 2011, was to the Board, and directed the deferral of consideration of all matters before the Board at that time pertaining to IIC rates and rate adjustments. Since the IICs are such a significant and integral component of Hydro's Cost of Service study, this directive effectively delayed the GRA filing.

Subsequent to the issuance of the Government directives on April 4, 2013 on the given rates policy matters, Hydro filed its GRA on July 30, 2013, less than four months later. The length of time between GRA filings has been cited as the dominant reason for Hydro's extended GRA hearing process. These delays occurred outside of Hydro's management control, and the delays therefore do not provide grounds for granting Hydro less than full cost recovery or impairing Hydro's opportunity to earn a reasonable return on its rate base.

B.1.2 Interim Applications

Hydro's original GRA proposed to adjust rates effective January 1, 2014. Hydro's position at the time was that delayed implementation of customer rates beyond January 1, 2014 would result in a material revenue shortfall. To provide an opportunity for recovery of the forecast cost to serve, Hydro filed an Interim Rates Application with the Board on November 18, 2013. The Board did not approve Hydro's application stating that the "the proposals in the Interim Rates Application raise complex and comprehensive issues which in the Board's view should be addressed before interim rates are established".[13]

[12] For OC2012-162, OC2012-175, OC2012-330, OC2013-048, OC2013-083 and OC2013-089 refer to CA-NLH-024, Attachments 9, 10, 12, 13, 14 and 15 respectively.
[13] Order No. P.U. 40(2013), page 3, lines 18-20.

To address the concerns with the Interim Rates Application, Hydro filed an amended Interim Rates Application on February 11, 2014. In Order No. P.U. 13(2014), the Board denied Hydro's Amended Interim Rates Application.

Throughout the current GRA process, Hydro has continued to file interim rate applications to provide an opportunity to recover the cost of serving customers and limit the revenue deficiencies to be required to be recovered from customers in future. These are as follows:

- Application filed May 12, 2014, denied by Order issued September 17, 2014;[14]
- Application filed on November 28, 2014, approved by Order issued December 24, 2014 (approving the 2014 revenue deficiency deferral account and segregating $45.9 million, denying other aspects of the application);[15]
- Application filed January 28, 2015, denied by Order issued May 8, 2015,[16] but approving specific portions and amounts effective July 1, 2015, as follows:
    - An interim increase of 8.0% in the base rate for NP;
    - An interim increase of 50% of the proposed increase in the rates for Government Diesel customers;
    - An interim increase of 10.0% in the base rate for IICs;
    - Changes to the RSP rules to allow a transfer from the IIC RSP surplus and to implement an IIC RSP rate so that there is an effective interim increase of 2.7% in IIC rates, including Teck; and
    - Changes to the RSP rules to allow a transfer from the IIC RSP surplus to fund the full amount of the 2014 year-end IIC RSP current balance.
- Application filed October 28, 2015 for approval of interim IIC electricity rates to be effective January 1, 2016, which was approved.[17]

With respect to these various interim rates and revenue deficiency applications, Hydro states that these were all made within its rights and duties to assure that it attains rates that allow it

[14] Order No. P.U. 39(2014).
[15] Order No. P.U. 58(2014).
[16] Order No. P.U. 14(2015).
[17] Order No. P.U. 35(2015).

to recover its costs and attain a reasonable rate of return as is required by the relevant legislation. Delayed rate implementation of customer rates beyond January 1, 2014 has resulted in Hydro incurring a shortfall of more than $100 million in cost recovery.[18] Hydro submits these costs were prudently incurred in providing service to customers and Hydro should be provided the opportunity to recover these costs, subject to the Board testing of these costs.

B.1.3 Innu Nation's Stated case

The Innu Nation and Hydro made submissions to the Board with respect to the Board's jurisdiction to grant the remedial relief requested by the Innu Nation with respect to compelling Hydro to provide service to customers in Natuashish. On September 4, 2015, the Board advised the parties that this matter was more appropriately dealt with in a separate proceeding and has since taken steps to retain counsel with regard to stating a case to the Court of Appeal pursuant to section 101 of the Act. Hydro therefore makes no further submissions on this matter at this time.

B.1.4 Approval of Settlement Agreements

There are two settlement agreements before the Board in this matter, the Settlement Agreement dated August 14, 2015 and the Supplemental Settlement Agreement dated September 28, 2015. Most of the issues settled relate to cost of service matters. Achieving these agreements enabled Hydro, the Parties, and the Board to reduce the length of the hearing and to forego the *viva voce* testimony of several expert witnesses.

These agreements were reached after detailed and involved negotiations. They constitute the common positions of the parties on these issues. All Parties were represented by learned and competent counsel and advised by experts. Hydro wishes to note its appreciation to the parties and to Board staff and external counsel whom assisted and cooperated in this matter. The settlement agreements are before the Board for its consideration.

[18] This reflects a $45.9 million shortfall based on the proposed 2014 Test Year Revenue Requirement and a $60.5 million shortfall based on the proposed 2015 Test Year revenue requirement.

Hydro joins the other Parties and Board external counsel in recommending their acceptance.

C. LEGISLATIVE REQUIREMENTS

C.1. LEGISLATION AND ORDERS IN COUNCIL

Hydro's Application seeks approval of rates under the Board's authority existing under sections 70 and 71 of the *Act*.

In carrying out its duties under the Act, pursuant to section 4 of the *EPCA*, the Board is required to implement the power policy stated in sections of the *EPCA*.

In addition to the rate and rule setting powers of the Board that exist under sections 70 and 71, the *Act* gives powers and guidance to the Board with respect to a number of determinations it has to make with regard to the rate setting process. These include the setting of rate base (section 78), the setting of return on rate base (section 80), and the determination and approval of a number of accounting matters (e.g., sections 67, 68, and 69).

Both the *Act* and the *EPCA* (section 4.1 of the *Act* and section 5.2 of the *EPCA*) contain provisions whereby the Lieutenant Governor in Council is empowered to exempt certain activities of public utilities from the Board's jurisdiction. The *EPCA* contains provisions (found in section 5.1) that empower the Lieutenant Governor in Council to give direction to the Board on power policy and rate setting matters.

Directions have been given to the Board under this section of the *EPCA* with regard to a number of rates policy issues. Attachments to CA-NLH-024 (Revision 1, March 23, 2015) provide 25 Orders in Council including:

- OC2003-347, with regard to the subsidization of rural rates;
- OC2009-063, with regard to Hydro's rate of return on equity;
- OC2013-089 (as amended by OC2013-207) with regard to the RSP Surplus; and

- OC2011-116, OC2011-388, OC2012-162, OC2012-175, OC2012-330, OC2013-048, OC2013-083 and OC2013-108 with regard to the timing of Hydro's GRA.

In addition, under OC2013-257 Hydro's activities with regard to the Exploits generation assets have been made exempt from the Board's jurisdiction and the Board was directed to include in Hydro's operating account the associated energy costs.

Three Orders in Council merit separate discussion because they concern matters of central relevance to the GRA.

C.1.1 OC2003-347 - Subsidization of Rural Rates

This Order in Council continues the longstanding policy of Government with respect to isolated rural rates. Notably, the policy directs the Board to set rates for Hydro's Isolated Customers such that "lifeline rates" are continued for domestic residential customers, preferential rates are provided to fish plants and to churches and community halls. OC2003-347 also directs that the Rural Deficit be charged to NP and Hydro's Rural Labrador Interconnected Customers. Pursuant to an Order in Council that is not directly relevant to the present proceedings but which was considered by the Board in Order No. P.U. 8(2007), the Board adopted a policy that Government department customers be charged rates designed to recover the full cost of service.

C.1.2 OC2009-063 - Return on Equity

This Order in Council directs the Board to set the same target ROE as most recently set for Newfoundland Power. The ROE is used in the determination of the setting of the return on rate base under section 80 of the *Act*.

The Lieutenant Governor in Council has directed that the Board, in calculating the return on rate base for Hydro, set the same target ROE as was most recently set for NP, either through a

GRA or calculated through the NP Automatic Adjustment Mechanism.[19] In Board Order No. P.U. 13(2013), the Board determined that NP's target return on common equity in 2015 would be 8.8%.[20]

Hydro submits that, in accordance with the Government's directive, the ROE to be used in this case for calculating Hydro's return on rate base is 8.8%.

In order to give effect to the spirit and intent of this directive, care must be taken to ensure that Hydro's return is not eroded or encroached upon by offsetting the return with some other amount or component of Hydro's costs. The Order in Council provides no authority to do so and none should be inferred.

In particular, Hydro objects to the suggestion made by the Consumer Advocate in its Issues List and cross-examination to the effect that the rate of return should be reduced or offset by some amount so as to effect a reduction in the Rural Deficit to be recovered from customers. To fully appreciate why this could clearly not be the intention of Government, a brief regulatory and legislative history of the Rural Deficit is useful. To this end, reference can be made to subparagraph 3(a)(iv) of the *EPCA*, which indicates that post 1999, the IICs are not required to fund a portion of the Rural Deficit.

Perhaps more useful for an understanding of this issue is the antecedent legislative provision, now repealed by the present *EPCA*, found in the *Electrical Power Control Act*, RSN 1990, C. E-5:

> ***Forecast costs***
>
> ***5.*** *Notwithstanding the other provisions of this Act, the hydro corporation shall include in its forecast costs filed with the public utilities board*
>
> > *(a) the amount to be allocated to retailers of the difference between the revenues and costs for the period April 1, 1989 to December 31, 1989 of*

[19] OC-2009-063.
[20] Order No. P.U. 13(2013), page 37.

the power distribution district related to the supply of power to its customers except those customers served from the Labrador interconnected electrical grid;

(b) the amount to be allocated to retailers of the difference between the annual revenues and costs of the hydro corporation, excluding all costs and revenues related to the supply of power to customers served from the Labrador interconnected electrical grid;[21] *and*

(c) the costs incurred after March 31, 1989, including fees or charges paid to the Crown, which have been deferred by the hydro corporation and which would, unless recovered from its customers, cause the hydro corporation to recover less than the minimum margin of profit approved by the public utilities board under subparagraph 3(c)(ii) in the year in which the costs were incurred.

Subsidies

6. *In determining the amounts to be included under paragraphs 5(a) and (b), the public utilities board shall take account of subsidies paid or payable by the Crown to the power distribution district until December 31, 1989 and to the hydro corporation after December 31, 1989 of $20 million for the period April 1, 1989 to March 31, 1990 and $10 million for the period April 1, 1990 to March 31, 1991.*

This legislative history provides an account of how the rural subsidy came into being as a fiat of the legislature and how it was treated. Prior to 1989, the Government fully funded the Rural Deficit incurred by the Power Distribution District in serving what are now Hydro's Rural Customers. The Power Distribution District was wound up at that time and its operations were absorbed into Hydro. Government made the above legislative change in 1989 to require that

[21] Legislation was subsequently modified (*EPCA*, 1994) requiring the Rural Deficit to also be recovered from customers on the Labrador Interconnected System.

the Board set rates such that Hydro would recover the Rural Deficit not from Government, as had been the case with the Power Distribution District, but from Hydro's customers, notably NP. As stated above and as can be seen from subparagraph 3(a)(iv) of the *EPCA*, until 1999 Hydro also recovered a portion of this deficit from the IICs.

The collection of the Rural Deficit from NP and from Hydro's Labrador Interconnected Customers, and not from Government, has been an ongoing regulatory issue. Hydro's collection of the Rural Deficit in this manner was an established and understood fact long before the directive as to Hydro's rate of return (OC-2009-063) was issued. Indeed, under paragraph (v) of Order in Council OC2003-347 it is expressly stated that this manner of funding is to "continue".

OC2009-063 is silent with regard to offsetting or reducing Hydro's ROE with a subsidy to fund the Rural Deficit (or by any other cost). The Consumer Advocate's expert witness, Mr. D. Bowman, accepts that Hydro now has what he calls a "mandated ROE" commensurate with that of NP, but suggests that the Board should consider directing a portion of Hydro's return toward payment of the Rural Deficit.[22] Hydro submits that the directive would be meaningless and ineffective if the Board could deny Hydro the mandated ROE by taking away some or all of the required return to serve other purposes.

The Consumer Advocate's proposition that Hydro fund a contribution to the Rural Deficit out of its rate of return cannot be reconciled with Government directives and the intentions implicit in them. First, it would restrict Hydro's recovery of the Rural Deficit from NP and from its Labrador Interconnected Customers (which is contrary to paragraph (v) of OC2003-347). Second, it would also amount to Government contributing toward the Rural Deficit since the funds would come from reduced earnings to which Government is entitled as Hydro's shareholder.

[22] Pre-filed Evidence of C. Douglas Bowman dated June 1, 2015, page 33.

C.1.3 OC2009-063 – Rate Base to Include Rural Assets

This directive also requires that the whole of Hydro's rate base be used for the purpose of setting Hydro's Rate of Return, including those assets deployed in the service of its rural customers. This Order in Council directs that a change occur from prior Board ordered policy whereby rural assets were excluded from rate base for the purpose of determining Hydro's rate of return.

C.2 2014 AND 2015 ALLOWED RETURN

OC2009-063 clearly and unambiguously states when the provisions of its direction regarding Hydro's ROE are to be implemented. The directive says that the Board shall adopt the policies set out therein for all future GRAs by Hydro, commencing with the first GRA by Hydro after January 1, 2009. The first GRA by Hydro after January 1, 2009 was the application in this case made by Hydro on July 30, 2013, requesting new rates to become effective January 1, 2014; and amended on November 10, 2014, requesting cost recovery for 2014 and new rates for 2015. According to the plain words of the Government directive, the Board is to adopt the polices set out in OC23009-063 in this GRA. It follows that the target ROE for both 2014 and 2015 must be the return most recently set by NP, namely, 8.8%.

C.3 TEST YEARS

Paragraph 3(a) (ii) of the EPCA reads as follows:

> *3. It is declared to be the policy of the province that*
> *(a) the rates to be charged, either generally or under specific contracts, for the supply of power within the province*
> *(ii) should be established, wherever practicable, based on forecast costs for that supply of power for 1 or more years,*

This provision provides ratemaking guidance to the Board and indicates that test years — "wherever practicable" — should be forecast test years. There are two circumstances where this requirement would not apply: (i) where the Board is specifically directed otherwise under section 5.1 of the *EPCA*; and (ii) where the Board in applying proper ratemaking principles deems that, for some reason, the use of a forecast test year is not practicable.

There were Government directives issued in the present matter as to the test year to be used. The first of these was OC2013-089 (replaced by OC2013-091 but unchanged in this regard), which was issued in April of 2013 and which directed that the Board use a 2013 Test Year. The test year aspect of the directive was rescinded by OC2014-319.

Hydro filed its GRA on July 30, 2013 in compliance with OC2013-089, as amended. When Hydro filed its GRA the Government-mandated test year was half over, so the GRA's 2013 Test Year was not a completely forecast test year.

Following its 2013 filing based on the mandated 2013 Test Year, Hydro filed for interim relief with the Board on several occasions as previously noted. Due to the passage of time without receiving an approved rate change and due to changes with respect to a number of cost elements, on June 6, 2014 Hydro advised the Board that it would be filing an amended GRA, which it did on November 10, 2014. That filing used (i) a 2014 Test Year for the purpose of testing the basis for Hydro's claimed 2014 revenue deficiency and (ii) a 2015 Test Year for the purpose of setting rates on a going forward basis. At the time of its filing, the 2015 Test Year was completely a forecast test year.

Although 2015 is now drawing to a close, this does not impair the relevancy or value of the test year information before the Board. Some modifications to the capital asset forecast used in the 2015 Test Year are required to determine the revenue deficiency for 2015. These adjustments are required to reflect the revenue requirement impact of delayed completion of some 2014 capital projects.[23] See Section D.1.2.3.

[23] See PUB-NLH-487.

For the purpose of rate setting, the 2015 Test Year remains the proper basis to be used for rate setting for the coming period starting in 2016.

C.4 PHASE IN OF INDUSTRIAL RATES

OC2013-089 and OC-2013-090 require the use of the RSP Surplus to phase-in of IIC rates over a three-year period. The phase-in period started September 1, 2013. The Board has used interim orders to achieve the phase-in. Upon approval of final GRA rates, Hydro will propose the conclusion of the rate phase-in to become effective September 1, 2016.

D. ISSUES AND ARGUMENT

In this section Hydro addresses:

- Issues affecting return;
- Revenue requirement issues;
- Cost of Service and Rates issues;
- Deferral and recovery mechanisms; and
- Management of the Rural Deficit.

Section D.1: Issues Affecting Return

D.1.1 Settled Matters

D.1.1.1 Allowable Range of Return on Rate Base

The Parties agreed the allowable range of return on rate base for Hydro will be ±20 basis points.[24]

D.1.2 Remaining Issues

D.1.2.1 Adjustment of Hydro's ROE

- ***Future changes to Hydro's 8.8% ROE should be implemented in a Hydro GRA.***

[24] Settlement Agreement, page 2, paragraph 7.

It has been suggested that, at such time as the Board reaches a decision to change the target ROE for NP, the Board could adopt an adjustment process to flow through the new ROE to Hydro.[25] Hydro proposes that any future changes to its ROE be implemented in a Hydro GRA.[26] This avoids implementation of new rates solely to give effect to an ROE change and means that the outcome of ROE changes can be implemented together with other impacts of a GRA decision. Further, the approach of implementing any future ROE changes in a Hydro GRA is consistent with the language of the Government directive, which sets out policies to be adopted by the Board "for all future General Rate Applications" by Hydro.

D.1.2.2 Assets in Rate Base

- ***For purposes of determining the revenue requirement for setting rates for 2016, Hydro's 2015 Test Year total plant in service is reasonable and should not be adjusted.***

Hydro's rate base is comprised of its investment in capital assets in use, deferred charges, fuel inventory, materials and supplies inventory, and cash working capital allowances.[27]

A detailed explanation of the updated 2015 capital expenditure amount has been provided in Hydro's evidence.[28] The increase in 2015 Test Year additions to plant in service is primarily due to the carry-forward of the in-service dates for the CT and other capital assets that were originally scheduled to go into service in 2014 but have now gone into service in 2015.

As stated in Undertaking No. 158:

> *The forecast additions to plant in service in comparison to the cumulative 2014 and 2015 Test Years is an underspend of less than 1%. Hydro does not propose to make the corresponding adjustment for rate setting purposes for 2016 given that the forecast assets in service in 2015 are consistent with the 2015 Test Year, all of*

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[25] November 16, 2015 Transcript, page 72.
[26] *Ibid*.
[27] Amended Application, Finance Evidence, Schedule I, page 5 of 11.
[28] *Ibid*.

the 2015 additions which were tested in the Hearing and will be in service for a full year in 2016, the planned growth in Hydro's capital program and the impact on return on rate base forecasted for 2016 in as outlined in PUB-NLH-487.[29]

The fact that the in-service dates of certain capital assets carried over from 2014 to 2015 should not impact Hydro's opportunity to begin recovering these costs in 2016. Further, Hydro undertook a very significant amount of capital spending in 2014 and 2015 to place the Holyrood CT and other used and useful assets into service, and Hydro should not be financially disadvantaged by the exclusion of this in-service capital for the purposes of rate setting.

If the impact of the delayed capital additions is not included in the 2015 Test Year for the purposes of rate setting, Hydro's 2016 forecast return on rate base would be 6.18%, which is below the lower end of the target range of return on rate base.[30]

D.1.2.3 Delayed In-Service Date of Capital Additions

- ***Adjustments to the Test Year plant in service to reflect delayed in-service dates are required only for the determination of net income deficiency.***

Hydro's 2014 additions to plant in service were less than expected. This difference reflected a delay in the in-service date of the Holyrood CT and the carry-over of other capital projects.[31] Grant Thornton identified $148 million of capital assets that did not go into service in 2014 as expected[32] and $110 million of this amount relates to the CT.[33] Hydro proposes adjusting the 2014 revenue deficiency to take into account the capital assets that were expected to be placed in-service during 2014 but were not.[34] In addition, to account for additions to plant in service

[29] Undertaking No. 158.
[30] PUB-NLH-487 (Revision 1, October 5, 2015).
[31] CA-NLH-326.
[32] Grant Thornton Financial Consultants Report, June 12, 2015, page 115, Table 87.
[33] PUB-NLH-487 (Revision 1, October 5, 2015).
[34] Undertaking No. 148.

that were delayed from 2014 to 2015, Hydro proposes to adjust the return for the 2015 net income deficiency by $5.1 million, as outlined in the 2015 Cost Deferral Application.[35]

To account for these delayed in-service dates, adjustments related to rate base should be made to determine the 2014 revenue deficiency and the 2015 revenue deficiency. However, as previous stated, adjustments related to rate base are not required and should not be made for setting rates for 2016 and beyond.

The delay in bringing assets into service has the effect of reducing 2014 Test Year revenue requirement by $2.1 million.[36] Excluding these capital additions for the 2015 Test Year would reduce revenue requirement by $5.1 million.

Section D.2: Revenue Requirement Issues

D.2.1 Settled Matters

D.2.1.1 Actuarial Gains/Losses in Employee Future Benefits

The Parties agreed the Board should approve Hydro's proposed accounting treatment to include actuarial gains and losses in EFBs in the 2015 Test Year.[37]

D.2.1.2 Expenses Associated with Asset Retirement Obligations

The Parties agreed the Board should approve Hydro's proposal to include depreciation and accretion expenses associated with asset retirement obligations with the amounts reduced from $3.1 million and $3.2 million for the 2014 and 2015 Test Years, respectively, as proposed in the Amended Application, to $2.6 million and $2.6 million, respectively. [38]

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[35] Cost Deferral Application, page 5.
[36] PUB-NLH-487, (Revision 1, Oct 5-15).
[37] Settlement Agreement, page 2, paragraph 8.
[38] Settlement Agreement, page 2, paragraph 9.

D.2.1.3 2015 Test Year Hydroelectric Energy Production

The Parties agreed to the methodology Hydro used to estimate its average annual hydroelectric energy productions and agreed that the Board should approve the 2015 hydraulic production calculation forecast of 4,604 GWh for all purposes, including the calculation of No. 6 fuel expense for the 2015 Test Year and for the RSP.[39]

D.2.1.4 2015 Test Year Depreciation Expense

The Parties agreed the depreciation methodology used to determine depreciation expense in the 2015 Test Year is appropriate.[40] Grant Thornton's review of Hydro's Amended Application included procedures to ensure that the depreciation rates used in the 2014 and 2015 Test Years are in compliance with the Gannett Fleming Depreciation Study and in compliance with Board Order No. P.U. 40(2012). In addition, Grant Thornton carried out other procedures, such as reconciling the detailed depreciation schedule to the pre-filed evidence.[41] As a result of completing its procedures, Grant Thornton noted no significant discrepancies in the calculation of the 2014 or 2015 Test Year depreciation forecasts.[42]

Grant Thornton noted that certain project costs are subject to the Prudence Review.[43] Subject to the decision of the Board with regard to the prudence of certain costs, Hydro submits that its 2014 and 2015 Test Year depreciation expense should be approved.[44]

D.2.1.5 CDM Cost Deferral and Recovery

The Parties agreed the Board should approve Hydro's proposal to defer and amortize annual customer energy conservation program costs, commencing in 2015, over a discrete seven year

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[39] Settlement Agreement, page 2, paragraph 10.
[40] Settlement Agreement, page 2, paragraph 11.
[41] Grant Thornton Financial Consultants Report, June 12, 2015, page 45.
[42] Grant Thornton Financial Consultants Report, June 12, 2015, page 47. The 2014 Test Year depreciation expense of $55.2 million reflects $239 million of assets that were expected to go in service in 2014 (CA-NLH-116). The total of $239 million for 2014 expected in-service assets includes the Holyrood CT, which actually did not go into service until early 2015. The delay in assets going into service, including the Holyrood CT, is $0.4 million in 2014 (Grant Thornton Financial Consultants Report, 2013 Amended General Rate Application, June 12, 2015, page 46).
[43] Grant Thornton Financial Consultants Report, June 12, 2015, page 31.
[44] Amended Application, Finance Evidence, Schedule II, page 1 of 1, line 19.

period in a CDM Cost Deferral Account. In the Supplemental Settlement Agreement, the Parties agreed the Board should approve Hydro's proposed CDM Cost Recovery Adjustment, which provides for recovery of the costs charged annually to the CDM Cost Deferral Account.[45]

D.2.1.6 GRA Costs

The Parties agreed the Board should approve Hydro's proposal to the Parties agreed the Board should approve Hydro's proposal to recover GRA costs (in an amount to be determined) over a three year period using straight-line amortization.

D.2.2 Remaining Issues

D.2.2.1 Operating and Maintenance Expenses

Salaries and Benefits

- ***Hydro's salary and benefits expenses for the 2014 and 2015 Test Years reflect prudent management decisions concerning the staffing levels necessary to maintain safe and reliable service, and Hydro's commitment to offer the competitive compensation packages necessary to recruit and retain a highly skilled workforce.***

Hydro's 2014 Test Year salary and benefits expense is $78.0 million. This amount includes a number of elements, such as salaries, overtime, capital labour costs, benefits, and cost recoveries. Excluding the other elements that make up the total salary and benefits amount, the 2014 cost of salaries is $73.2 million and the 2014 benefits expense is $18.1 million. In the 2015 Test Year, the salary and benefits expense is $85.8 million, the cost of salaries is $77.9 million and the benefits expense is $23.5 million.[46]

Employee benefits include fringe benefits, EFBs and group insurance.[47] Fringe benefits generally are CPP, EI, PSPP and Workers Compensation premiums and contributions paid by Hydro.[48] EFBs relate to severance payments upon retirement and health benefits provided to retirees on

[45] Supplemental Settlement Agreement, page 3, paragraph 12.
[46] Amended Application, Regulated Activities Evidence, page 2.33, Table 2.4.
[47] Amended Application, Regulated Activities Evidence, page 2.33, Table 2.4.
[48] Amended Application, Regulated Activities Evidence, pages 2.36, lines 19-21.

a cost-shared basis.[49] Group insurance benefits provide Hydro employees with health, dental, life insurance and accidental death and dismemberment coverage.[50]

The total cost of employee benefits in the 2014 Test Year is an increase of $3.6 million over 2007 actual costs of $14.5 million. The total cost of employee benefits in the 2015 Test Year is an increase of $9 million over 2007 actual costs.[51] The cost of fringe benefits, in particular, was driven higher in 2014 and then again in 2015 by increased premiums for EI and CPP and increased contributions to the PPSP, in combination with salary increases discussed below. As well, there is an additional expense of $2.5 million in 2015 associated with PSPP changes announced by the Government that result in higher employer contributions.[52]

In the 2015 Test Year, the cost of EFBs is $2.5 million higher than 2007 actual costs; this increase includes actuarial losses of $1.6 million.[53] The Settlement Agreement recommends that the Board approve recognition of these costs in the 2015 Test Year.

In 2006, based on an analysis of its workforce and the external labour market, Hydro identified the importance of focusing on recruitment and retention of skilled employees. The factors that dictated the need for a focused recruitment and retention strategy included the following:

- Significant anticipated retirements during the coming five to ten years;
- Large scale construction projects within the province and Western Canada;
- Changing labour force demographics, specifically, an aging population and fewer labour market entrants; and
- Stable or declining participation trends in the trades and engineering occupations.[54]

[49] Amended Application, Regulated Activities Evidence, page 2.37, lines 7-8.
[50] Amended Application, Regulated Activities Evidence, page 2.37, lines 20-21.
[51] Amended Application, Regulated Activities Evidence, page 2.33, Table 2.4.
[52] Amended Application, Regulated Activities Evidence, pages 2.36, lines 21-23 to 2.37, lines 1-4.
[53] Amended Application, Regulated Activities Evidence, page 2.37, lines 13-15.
[54] Amended Application, Introduction Evidence, Section 1.2.3, page 1.15, lines 14 - 19.

Over the period from 2007 to August 31, 2014, there were 238 retirements from Hydro and it is anticipated that, between 2014 and 2022, 40% of Hydro's current workforce will be eligible for retirement.[55] The fact that employees who leave Hydro are often among the most experienced and knowledgeable members of the workforce adds emphasis to Hydro's focus on minimizing voluntary turnover.[56]

Hydro's forecast costs for salary and benefits reflect a need for Hydro to offer a compensation package that takes into account the labour market in the Province. As well, it has been necessary for Hydro to address differentials in the wages that it offers, as compared to NP and other Atlantic Canada utilities. These wage differentials arose primarily because of the government's previous wage restraints that were applied to Hydro.[57]

Thus, in recent years, Hydro has made adjustments to salaries and wages that are necessary and appropriate to fulfill key business purposes. First, these adjustments are necessary in order to meet Hydro's central concern to ensure it is paying fairly and competitively as an employer. Ensuring that Hydro's employees are paid fairly is a matter both of equity and of good business practice.[58] Second, Hydro must be able to attract and retain the people needed to run its operations effectively.[59] In order to attract and retain the employees that it needs, Hydro aims to pay its employees fairly and equitably relative to their peers in the industry and, in particular, the Atlantic Canada utility industry. As Mr. McDonald for Hydro noted: "[t]here's no reason in this world why anyone of our people who are highly qualified people in Hydro should be paid any less or differently from a comparison perspective than anybody with any of these other utilities."[60]

[55] Amended Application, Introduction Evidence, pages 1.15, lines 22 to 24.
[56] Amended Application, Introduction Evidence, pages 1.15, lines 26-28 to page 1.16, lines 1-2.
[57] Amended Application, Regulated Activities evidence, page 2.34, lines 9 - 16.
[58] September 16, 2015 Transcript, pages 169-170.
[59] September 16, 2015 Transcript, pages 169-170.
[60] September 17, 2015 Transcript, pages 76-77.

The labour market in the Province has experienced salary increases well beyond inflation over the years from 2007 to 2015. Without even taking into account the skilled and specialized employees that Hydro needs in many areas, Hydro is faced with the reality that average weekly earnings in the Province have escalated by 35% over that period of time.[61]

In order to be able to attract and retain talented and specialized employees in these market conditions, Hydro must be in a position to compete with its primary comparators on salaries and wages. For comparative purposes, Hydro looks to other utilities, primarily in Atlantic Canada and most notably, NP. As an example, the wage rate of a line worker at Hydro in 2015 is $38.17 per hour. This compares to $39.10 per hour at NP and the Atlantic Canada utility average in 2015 of $38.42.[62]

In managing towards the Atlantic Canada utility average as the benchmark for employee compensation, Hydro has taken a conservative approach. The evidence reveals a number of areas where Hydro has been "much more conservative" than the recommendations of its expert compensation consultant.[63]

The expert consultants who collect information on employee compensation provide a range of data points for particular job categories and, in utilizing this information, some companies have adopted a philosophy described in the evidence as "broad-banding". While Hydro is aware of this practice, it decided to stay with, or "steward" towards, mid-points. For certain job categories ("Hay 15" through "Hay 18"), Hydro's expert consultant cast the data on a national basis, but Hydro asked that the numbers be scaled back to Atlantic Canada data.[64] When the expert consultant recommended that Hydro immediately take steps to address job categories ("Hay 11" through "Hay 18") in which Hydro was lagging relative to the other Atlantic Canada utilities, Hydro decided to correct the lag naturally through the salary administration process.

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[61] September 16, 2015 Transcript, pages 143-144.
[62] September 16, 2015 Transcript, page 145.
[63] September 16, 2015 Transcript, page 164.
[64] September 16, 2015 Transcript, pages 160 and 162.

This took on average two years, rather than the immediate correction recommended by the consultant.[65] The expert consultant recommended that short term incentives be made available down to a certain level of job category ("Hay 13"), but Hydro decided not to "dip down that far in the organization" with incentive pay.[66] The expert consultant recommended that employees be able to earn beyond the posted target amount for short-term incentives, but Hydro decided to cap payouts at the stated amounts.[67]

Overtime

- ***Hydro's overtime costs reflect the aging of Hydro's assets in the face of increased customer and increased reliability expectations. Hydro has made a productivity commitment by constraining overtime costs in the 2015 Test Year and going forward until Hydro's next GRA.***

Hydro incurs overtime costs as it carries out work to fulfill its mandate of providing least cost reliable service. The need for overtime varies depending on the circumstances at any particular time. Where possible, Hydro minimizes overtime through work planning and filling vacant positions. Nevertheless, the drivers of overtime costs include emergencies – which may arise due to weather and equipment related outages – labour shortages and capital project requirements. Overtime is also required to plan outages at times which are least inconvenient to customers such as weekends and early mornings As well, overtime occurs because of compensation paid to shift workers who must work on statutory holidays and it is necessary at times to minimize customer outages or to minimize customer service interruption risks.[68]

Hydro's overtime costs included in the 2014 Test Year are $12.2 million, which is $6.0 million higher than actual overtime costs in 2007. Of the 2014 Test Year overtime amount, $5.4 million is capitalized, compared to an actual amount of $1.7 million that was capitalized in 2007. The

[65] September 16, 2015 Transcript, pages 162-163.
[66] September 16, 2015 Transcript, page 164.
[67] September 16, 2015 Transcript, page 165.
[68] Amended Application, Regulated Activities Evidence, page 2.35.

net impact of these variances is that operating overtime costs in the 2014 Test Year are $2.3 million higher than actual 2007 costs. In 2014, higher overtime costs were driven by incremental work requirements arising from the January 2014 outage as well as emergency call-outs. The higher amount of capitalized overtime in 2014 is primarily due to an increase in Hydro's capital program and higher salary costs during the period.[69]

Hydro's overtime costs included in the 2015 Test Year are $10.1 million, or $2.1 million less than the 2014 Test Year amount. Of the 2015 Test Year amount, $5.2 million is capitalized, which is an increase of $3.5 million over the actual amount of $1.7 million that was capitalized in 2007. The net impact of these variances is that operating overtime costs in the 2015 Test Year are only $0.4 million higher than actual 2007 costs. As well, operating overtime costs in the 2015 Test Year are $2.1 million less than in the 2014 Test Year.[70]

Hydro is experiencing pressure on its overtime costs for a number of different reasons. The aging of Hydro's assets and the need to get generation back up quickly when problems arise with these assets, the growth of demand on the system, the need to complete capital projects within tight timelines, and the need to minimize impacts on the power system and on customers, all contribute to a growing and pressing requirement for overtime.[71] A more specific example of these pressures on overtime costs is the Holyrood facility, where there has been an increase in electrical maintenance, instrumentation and mechanical maintenance to address the increasing corrective maintenance requirements that are becoming evident at the plant.[72]

Hydro has made a productivity commitment by constraining overtime costs in the 2015 Test Year and going forward until Hydro's next GRA.[73] As already stated, operating overtime costs included in the 2015 Test Year for rate-setting purposes are $2.1 million lower than 2014

[69] *Ibid*.
[70] *Ibid*.
[71] September 23, 2015 Transcript, page 168.
[72] September 23, 2015 Transcript, page 171.
[73] September 23, 2015 Transcript, page 170-171.

operating overtime costs and only $0.4 million more than actual costs in 2007. Hydro will limit overtime costs through efforts such as improved efficiency in the planning, scheduling and execution of work and the redeployment of resources in certain key areas.[74]

Vacancies

- ***Hydro's 2014 and 2015 Test Years demonstrate an inverse relationship between the vacancy allowance and the amounts spent on overtime and labour; Hydro's vacancy allowance of 40 FTEs for the 2015 Test Year is the correct number for the long term.***

Hydro uses a number of factors to determine an appropriate vacancy allowance to apply to its salary budget based on a combination of previous vacancy experience, most recent labour conditions (trending on job competitions), and anticipated retirements and turnovers.[75] Hydro experienced higher vacancy than anticipated in 2014. The 2014 Test Year includes a vacancy adjustment of 20 FTEs as outlined in Undertaking No. 145, which is estimated to be the equivalent of $1.7 million at an average salary of $85,000 per FTE.[76] However, with consideration of extraordinary factors including Hydro's deferral of apprentice hiring and the impact of work covered through contract labour and overtime, the 2014 vacancy rate would be normalized to less than 40.[77] Hydro did not achieve savings relative to the 2014 Test Year due to the higher 2014 vacancy allowance as a result of increased overtime and contract costs incurred resulting from the higher number of vacant positions.[78]

The 2015 Test Year includes an appropriate vacancy allowance of 40 FTEs or $3.3 million.[79] While the company's vacancy experience is currently higher than its budgeted allowance, the vacancy allowance is appropriate as Hydro has incurred additional costs again in 2015 relating to managing its vacancies with the use of overtime, contract labour, etc., as outlined in

[74] September 23, 2015 Transcript, pages 170-171.
[75] CA-NLH-104 (Revision 1, Dec 18-14), page 2, lines 9-22.
[76] See CA-NLH-104, Revision 1, page 2, lines 9 – 22.
[77] September 16, 2015 Transcript, page 176-177.
[78] See Undertaking No. 146.
[79] See response to IC-NLH-005 (Revision 1, Dec 3-14).

Undertaking No. 146. As well, Hydro notes in testimony by Mr. McDonald that while the vacancy rate is higher in 2015, it is Hydro's position that an allowance of 40 FTEs is appropriate for the longer term (i.e., exclusion of extraordinary factors).[80]

Hydro reviews its resource requirements and makes prudent decisions based on circumstances and priorities that benefit Hydro customers. Hydro's costs include all factors affecting resourcing of work and is not limited to strictly salaries and wages less vacancy allowance. Hydro will continue to reallocate work where appropriate using a mix of temporary resources, contract labour and overtime.

Intercompany Charges

- ***Intercompany services provide significant benefits to Hydro's customers. The charges for these services are subject to transaction costing guidelines that have been reviewed favorably by Hydro's independent auditor and the Board's financial consultant.***

Since the last GRA, Hydro has become a subsidiary of Nalcor Energy, which has a number of other subsidiaries. Nalcor has adopted a matrix model approach to the sharing of its services and activities with its affiliates.[81] To the extent that resources were based within Hydro and could be effectively shared with affiliates without impeding Hydro's use of those resources, Hydro has been able to recover the costs of those resources from its affiliates, thereby lowering the overall cost of providing electrical service.[82] These cost savings have come in the form of increased recoveries from the Admin Fee as well as the sharing of resources.

The sharing of services is subject to ITC Guidelines.[83] The ITC Guidelines set parameters for the sharing of services among the Nalcor lines of business through the Admin Fee as well as the costs associated with the provision of services via the Corporate Services group.

[80] September 16, 2015 Transcript, page 180, lines 17-20.
[81] September 9, 2015 Transcript, pages 73-76.
[82] PUB-NLH-141.
[83] Amended Application, Volume II, Exhibit 8.

Through the shared services model, Hydro is able to benefit from the optimization and efficiency of certain services being provided on a shared basis to affiliates within the Nalcor organization. Provision of shared services at cost facilitates the sharing of services and supports the optimal and most efficient use of resources. Accordingly, Hydro does not charge a mark-up on intercompany transactions.[84]

Deloitte conducted an independent review and noted that a common or shared services model allows organizations such as Nalcor and its affiliates to optimize assets and resources to provide efficient or specialized services at potentially lower costs than each individual entity replicating the asset or service.[85] Deloitte concluded "the methodologies and practices adopted by Nalcor are fair and reasonable and in line with other utilities."[86]

In the GRA, the Board retained Grant Thornton to provide a report and testimony by Mr. Rolph on Hydro's shared services model and inter-company transactions policy. Grant Thornton also conducted a review of "the reasonableness of the methods used by Hydro and its affiliates to determine the amounts charged by and to Hydro".[87] Based on a survey of other Canadian regulated utilities, Mr. Rolph did not identify any significant issues or problems with the application of the shared services model as applied by Hydro and found that the approach used provides value to Hydro and to its affiliates.[88] In its conclusions, Grant Thornton indicated that, among other things, Hydro and its affiliates derive value from the corporate services rendered by each other.[89]

The specific findings reported by Grant Thornton as a result of its review include the following:

[84] CA-NLH-083.
[85] NP-NLH-024, Attachment 1, page 3.
[86] NP-NLH-024, Attachment 1, page 4.
[87] Grant Thornton Expert Report, June 1, 2015, page 1, section 1.3, where it is said that this Report "builds on" the previous Grant Thornton Report dated April 25, 2014.
[88] Grant Thornton Expert Report, June 1, 2015 page 59.
[89] Grant Thornton Expert Report, June 1, 2015, page 59.

Common Services:[90]

- Using an indirect charge method to determine an arm's length price for the common services Hydro renders to its affiliates is reasonable;
- Allocating the HR and safety and health related costs to be recovered using FTEs as the allocator is reasonable;
- Allocating the IS related costs to be recovered using average number of users as the allocator is reasonable;

Common Expenses:[91]

- Allocating the building rental costs using square footage occupied as the allocator is reasonable;
- Allocating the telephone infrastructure-related cost using the average number of users is reasonable;
- Treating these common expenses as flow through costs and charging them back without a mark-up is reasonable;

Corporate Services[92]

- It is reasonable for Hydro and its affiliates to use a direct charge method;
- The labour rates used to recover the costs appear to be fully burdened; and
- Unless the ultimate recipient of the corporate service is an energy project involving private interest, not applying a mark- up to the costs of rendering corporate services to be recovered is reasonable.[93]

Grant Thornton noted that the common services related to the Admin Fee might not be fully burdened.[94] Hydro acknowledged this point[95] and provided evidence indicating that the impact

[90] Grant Thornton Expert Report, June 1, 2015, page 2.
[91] Grant Thornton Expert Report, June 1, 2015, pages 2-3.
[92] Grant Thornton Expert Report, June 1, 2015, page 3.
[93] The ultimate recipients of corporate services do not include any energy projects involving "private" interests. CF(L)Co is the only recipient of corporate services that is not ultimately owned 100% by the Province (November 17, 2015 Transcript, pages 81-83). Transactions between Hydro and CF(L)Co do not include a mark-up in accordance with the contract between them (NP-NLH-214) and, in any event, the impact of any such mark-up would be $41,000 and $44,000 in the 2014 and 2015 Test Years, respectively (Undertaking 152).
[94] Grant Thornton Expert Report, June 1, 2015, page 2.

of calculating a fully burdened Admin Fee is $105,000 in the 2014 Test Year and $115,000 in the 2015 Test Year.[96]

Hydro has demonstrated significant benefits to ratepayers from the Admin Fee. The amounts recovered by Hydro through the Admin Fee for the provision of services to Nalcor affiliates are $5.6 million in the 2014 Test Year and $5.7 million in the 2015 Test Year.[97] Hydro has estimated a benefit of $9.1 million from the initial transfer of staff from Hydro to Nalcor.[98] Hydro's customers benefit from the sharing of services with Nalcor, rather than Hydro employing its own dedicated full-time resources to provide those services.

Grant Thornton's annual review of Hydro also encompassed a review of non-regulated activity.[99] No issues regarding non-regulated transactions or cost allocations have been brought forward by Grant Thornton, or indeed by any party to this proceeding.

System Equipment Maintenance

- ***Hydro's increased SEM costs are justified by Hydro assuming responsibility for costs previously incurred by TwinCo; by new demands imposed by the newly installed Holyrood CT; and by the increased preventative and corrective maintenance, including vegetation management.***

General

Hydro's actual costs for SEM were $7.5 million in 2007. These costs have increased by $3.2 million in the 2014 Test Year and by a further $4.1 million in the 2015 Test Year.[100]

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[95] November 16, 2015 Transcript, page 10.
[96] Undertaking No. 151.
[97] PUB-NLH-169 (Revision 4, Dec 3-15).
[98] NP-NLH-084.
[99] PUB-NLH-140, Attachment 1, pages 5-6.
[100] Amended Application, Regulated Activities Evidence, pages 2.45-2.46.

There are a number of key drivers of Hydro's increased requirements for spending on SEM. Two of the primary drivers that increase the SEM costs in the 2015 Test Year forecast are the costs previously incurred by TwinCo and the costs associated with the new Holyrood CT. Other drivers of higher SEM costs are initiatives focused on improving transmission and distribution reliability performance, including vegetation management.

TwinCo Assets

CF(L)Co continues to operate and maintain the transmission assets previously owned by TwinCo on Hydro's behalf.[101] The 2015 Test Year includes forecast operating and maintenance costs of approximately $2.8 million for the transmission lines and the terminal station.[102] The work giving rise to these costs was previously done for TwinCo by CF(L)Co and now is done for Hydro by CF(L)Co. Hydro worked very closely with CF(L)Co to develop the budget amounts based on CF(L)Co's experience with the costs to maintain and operate the assets over the past number of years.[103]

Hydro provided detailed support for the 2015 Test Year forecast operating and maintenance costs.[104] No issue has been raised during this proceeding about these costs.

Holyrood CT

Hydro's SEM costs for the 2015 Test Year include costs of $1 million associated with maintenance of the new CT, as well as an additional $1.6 million in respect of the extended (two year) warranty that provides for technical oversight and coaching from the Engineering, Procurement and Construction contractor related to the operation and maintenance of the unit.[105] Hydro submits that the operating and maintenance costs applicable to the Holyrood CT are reasonable for the provision of reliable service to customers.

[101] PUB-NLH-367.
[102] Amended Application, Regulated Activities Evidence, pages 2.12 and 2.46; PUB-NLH-367.
[103] September 24, 2015 Transcript, pages 38-40.
[104] PUB-NLH-367.
[105] Amended Application, Regulated Activities evidence, page 2.46.

Preventative and Corrective Maintenance

The cost increase to improve transmission and distribution reliability performance and maintenance in 2014 is primarily related to the completion of $1.0 million in preventative and corrective maintenance backlog work associated with critical power transformers, air blast circuit breakers and protection and control systems costs associated with the completion of the preventive and corrective maintenance backlog for 2015 were forecast to be $1.2 million. However, as these costs are not considered to be reflective of normal operating conditions, Hydro proposes a deferral of the costs over a five-year amortization period beginning in 2015 and the 2015 Test Year includes $0.2 million of related amortization.[106]

Hydro's vegetation management costs increased by $1.4 million in the 2014 Test Year, as compared to 2007; and by an additional $0.5 million in the 2015 Test Year.[107] The higher costs of vegetation management result from both an increase in contractor costs and a greater amount of work. The contractor for Hydro's vegetation management work was selected through a public tender process and the outcome of the process was a higher contract cost than that which was reflected in Hydro's 2007 costs.[108] As well, Hydro found that additional vegetation management is needed on dams and dykes and along transmission lines after a number of interruptions were experienced due to tree contact:

> *JOHNSON, Q.C.:*
> *Q. Okay. As regards vegetation management, that's referenced on page 2.46, line 21, further increase of a half million dollars related to vegetation management. That's a fairly significant increase in the cost for vegetation management. I think you'll agree.*

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[106] Amended Application, Regulated Activities Evidence, pages 2.45-2.47 and 3.23.
[107] Amended Application, Regulated Activities Evidence, page 2.46.
[108] September 24, 2015 Transcript, page 37.

MR. HENDERSON:

A. It is, and it is specifically to address vegetation management requirements of the company. We had experienced a number of customer interruptions due to tree contact and we had a look and saw that we needed to put in some extra effort there to stay ahead of what we were experiencing, which was a -- we weren't staying ahead of the growth of vegetation along our transmission lines and also on our dams and dikes, so we had to put in a bit more, and there was also an increase in the contract costs. When we went to tender for that, the costs have gone up as well.[109]

Professional Services

- ***Hydro's expenditures for professional services reflect ongoing increases in regulatory activity. In addition, Hydro is incurring increased costs for asset assessments, and the development of operations, maintenance and retirement plans tailored to Hydro's aging asset portfolio.***

The cost of Professional Services in the 2014 Test Year is $10.6 million, which is an increase of $6.8 million over 2007 actual costs. The 2015 Test Year cost of Professional Services declined from the 2014 Test Year to $8.4 million which is $4.6 million higher than 2007 actual costs.[110] The major causes of the increase in Professional Services expenses from 2007 to the 2014 Test Year were higher consulting costs ($5 million more than 2007) and GRA and Board related costs ($2.9 million more than 2007). Consulting costs were higher for a number of reasons, one of which was the Outage Inquiry (accounting for $2 million of consulting costs in 2014). GRA and Board related costs in the 2014 Test Year were higher as a result of a marked increase in the volume of applications and regulatory activity.[111]

[109] September 24, 2015 Transcript, pages 36-37.
[110] Amended Application, Regulated Activities Evidence, pages 2.39-2.40 and Table 2.7.
[111] Amended Application, Regulated Activities Evidence, page 2.40.

Consulting costs are $3.4 million higher in the 2015 Test Year than in 2007 for reasons that include regulatory studies and filings, environmental work and safety and health related programs and condition assessments. GRA and Board related costs are $1.7 million higher in the 2015 Test Year compared to 2007 actual costs because of an increased volume of applications and regulatory activity.[112]

One driver of higher consulting costs is a requirement for condition assessments of assets to verify the timing of overhauls and replacements under the long term asset plan. Another driver is the need to evaluate the extent to which Hydro's operating and maintenance activities should be adjusted or modified to take into account the condition of assets.[113]

External GRA Costs

- ***The external GRA costs reflected in the 2014 and 2015 Test Years are reasonable and full cost recovery is justified in light of the level of recent regulatory activity during this period.***

Hydro's 2014 Test Year revenue requirement includes $1 million in external GRA costs. Hydro's 2015 Test Year revenue requirement includes $333,333 in deferred rate hearing costs (also known as deferred regulatory costs),[114] reflecting the recovery of $1 million of GRA costs amortized on a straight-line basis over a three-year period.[115] As part of their settlement agreement, the Parties agreed to Hydro recovering its GRA costs evenly over a three-year period.[116] The External GRA Costs are included in the professional services costs discussed above.

The amount to be recovered remains at issue. Hydro proposes that the Board approve an update to the 2015 Test Year GRA costs to permit recovery of the actual costs incurred.

[112] *Ibid*.
[113] September 22, 2015 Transcript, pages 99-100.
[114] Amended Application, Finance Evidence, Schedule I, page 9, line 28.
[115] Amended Application, Finance Evidence, page 3.22, lines 7 to 13; IC-NLH-053 (Revision 1).
[116] Settlement Agreement, August 14, 2015, pages 4, paragraph 18.

Hydro notes the timing of Hydro's current GRA was determined primarily by the Government's direction on rates policy.[117] Moreover, it is quite likely the cost of one conducting one GRA in seven years may compare favorably to the cost of conducting two GRAs either three years apart:

> *With regard to regulatory efficiency, Hydro believes there is a trade-off when longer periods occur between GRAs. Because, typically, the prime reason to file a GRA is the need to increase customer rates, the decision to take other steps which results in fewer GRAs will usually result in fewer rate increases to customers and lower overall regulatory costs due to the avoidance of GRAs in the intervening years. It appears to be true that there is an increased complexity and scope of GRAs that occur after several years have passed but, overall, Hydro believes deferring GRAs when it is reasonable to do so reduces the regulatory costs borne by the customer.*[118]

Hydro submits the Amended Application became necessary because of changes in its forecast costs since filing the 2013 GRA. The prudent course of action was to amend the application rather than concluding the GRA and filing another GRA immediately thereafter:

> *MR. O'BRIEN:*
> *Q. Okay, let me ask you sort of - I'll take you a year later then to the point where there was a decision made at Hydro, I guess, to amend the filing for 2013 to update it, I guess, in November of 2014. Can you give me your recollections as to the reasons why that was done and who was involved with making that decision?*
>
> *MR. HENDERSON:*
> *A. That was - the people who were involved in that would have been myself, and the CFO, Mr. Sturge, the General Manager of Finance, and the Rates and*

[117] NP-NLH-369.
[118] CA-NLH-002, page 2, lines 17 to 24.

> *Regulatory Manager. It was presented to me, the financial outlook for the coming year, we had updated some financial plan information, and given the length of time that it had occurred with respect to the 2013, which was the test year, versus where we were seeing things were going, with that length of time that had transpired, we felt that in terms of Hydro's financial outlook, it looked to be - it was most appropriate to file with additional information to update and go forward with the 2014 and 2015 test year. If that wasn't the case, it was very likely that we would have to turn around and have another application right after the 2013 one, you know, with the 2013 test year, and that would have certainly been, I'll say, inefficient in the sense of us going through the regulatory process and we thought at that time the appropriate thing to do was to file for 2014 and 2015 test year.*[119]

Hydro has agreed with other parties that it will file its next GRA no later than March 31, 2017.[120] In preparation for the next GRA, Hydro has agreed that it will file a marginal cost study no later than December 31, 2015; a cost of service methodology report no later than March 31, 2016; and a report on the Rate Stabilization Plan and supply cost recovery mechanisms no later than June 15, 2016.[121] Furthermore, Hydro and the other parties have agreed that a generic Cost of Service hearing will be held following the filing of these reports.[122]

The busy regulatory calendar for 2016 supports the level of regulatory costs included in the 2015 Test Year as it is expected to continue at the 2015 Test Year level for 2016.

CDM

- ***Hydro's CDM initiatives are cost justified and consistent with the provision of least cost reliable service.***

[119] September 23, 2015 Transcript, page 6, line 14 to page 7, line 21.
[120] Settlement Agreement, August 14, 2015, page 5, paragraph 23(d).
[121] Settlement Agreement, August 14, 2015, page 5, paragraph 23(a) to (c).
[122] Settlement Agreement, August 14, 2015, page 5, paragraph 23.

For the Island Interconnected System, Hydro delivers energy efficiency programs in a joint effort with NP under the takeCHARGE initiative.[123] The utilities use the Total Resource Cost test (a cost-benefit analysis) to evaluate the economics of the energy efficiency programs.[124]

CDM Plan initiatives include activities to encourage behavioural change by customers, the provision of rebates, marketplace promotions and other efforts targeted at reducing reliance on electricity.[125]

Under the takeCHARGE brand, Hydro also has implemented CDM programs such Isolated Systems Community Energy Efficiency Program and the Isolated Systems Business Efficiency Program, which target isolated diesel communities. The measures implemented by Hydro in isolated communities have achieved total energy savings of 4.3 GWh from 2012 to 2014.[126] Hydro's CDM initiatives in isolated diesel communities help to constrain the growth of the Rural Deficit.

Hydro also maintains the Industrial Energy Efficiency Program to assist in determining the appropriate program design and components for an industrial customer energy efficiency initiative.

Hydro's initiative to improve energy efficiency at its own facilities has been implemented at many facilities across the Province and at Hydro's head office in St. John's. The internal energy conservation steps taken by Hydro have resulted in an estimated 9.5 GWh of energy savings from 2009 to 2014.[127]

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[123] PUB-NLH-313.
[124] The economic tests are updated annually for the programs and are included in NP's CDM reports that are filed annually with the Board.
[125] Amended Application, Introduction Evidence, page 1.14.
[126] IN-NLH-241, Attachment 1, page 6, Table 2.
[127] IN-NLH-239, page 3 of 4, Table 2.2.

Other Income and Expenses

- ***Hydro should be allowed full recovery of its Other Income and Expenses, because the claimed Test Year amounts are within expected levels and unchallenged.***

In this application, "other income and expense" refers to costs associated with the loss on disposal, removal cost and insurance.[128] Hydro's 2014 Test Year and 2015 Test Year amounts for "other income and expense" are $2.1 million and $4.1 million respectively.[129] As can be seen from the Grant Thornton's report, the forecast asset disposal costs of $2.1 million and $4.1 million for the two respective years include a number of constituent elements, such as the net book value of assets that are being retired, proceeds on disposal of assets and removal costs.[130] Hydro's treatment of these asset disposal costs is in accordance with Board Order P.U. 40(2012).

The evidence shows that the 2014 and 2015 Test Year amounts for other income and expenses fall in line with the three-year average of the actual loss on disposal ($3.3 million).[131] Hydro's evidence explains how the forecast costs were developed on the basis of a project-by-project assessment of work that results in the retirement of existing assets.[132]

No intervenor raised any issues with the other income and expense category of costs and Hydro submits that the costs as set out in its evidence[133] should be approved.

D.2.2.2 Supply Costs

- ***Supply costs for 2015 Test Year should reflect a No. 6 fuel cost of $64.41 (Cdn) per barrel.***
- ***Supply costs incurred at HTGS should be based on a 2015 Test Year fuel conversion factor of 607 kWh/bbl.***

[128] NP-NLH-319.
[129] Amended Application, Finance Evidence, Schedule III, page 1 of 2, line 32.
[130] Grant Thornton Financial Consultants Report, June 12, 2015, page 84, Table 72.
[131] NP-NLH-319.
[132] NP-NLH-318.
[133] Amended Application, Finance Evidence, Schedule III, page 1 of 2, line 32.

- ***Hydro's Capacity Assistance agreement costs for the 2014 and 2015 Test Years benefit customers and should be approved for inclusion in Hydro's revenue requirement.***
- ***Supply Costs on the Isolated Systems and the Labrador Interconnected System are reasonable.***

Overview

Hydro's supply costs principally consist of purchases of No. 6 fuel for Holyrood, purchases of diesel and gas turbine fuel, and power purchases from other suppliers. Table 1 provides the proposed 2015 Test Year fuel costs that Hydro recommends for use in setting customer rates reflecting the correspondence provided to the Board on October 28, 2015.

Table 1 Supply Costs by Type for 2015 Test Years
($ Millions)

Supply Cost	**2015 Test Year**
No. 6 Fuel (net of RSP deferral)[134]	$169.0
Diesel and gas turbine fuel[135]	21.4
TOTAL	190.4
Fuel Supply Deferral[136]	2.0
NET FUEL COST	**192.4**
Power purchases[137]	59.9
TOTAL SUPPLY COST	**251.3**

The elements of Hydro's supply costs are discussed separately below.

[134] Amended Application, Finance Evidence, Schedule III, line 23 and line 24.
[135] Amended Application, Finance Evidence, Schedule III, line 26.
[136] Amended Application, Finance Evidence, page 3.12, Table 3.3 Reflects a 5-year amortization of 2014 capacity related supply costs of $9.65 million.
[137] Amended Application, Finance Evidence, Schedule III, line 26.

Island Interconnected Supply Costs

No. 6 Fuel

Forecast production at the HTGS is a function of forecast load less Hydro's own hydraulic generation, power purchases, and standby generation as shown in Table 2.

Table 2

Island Interconnected Supply		
Line No.	**Particulars**	**Energy (GWh)**
1	**NLH Hydroelectric Generation**	**4,604**
2	Power Purchases	
3	Nalcor Exploits and Star Lake	776
4	Wind	189
5	CBPP Cogen	51
6	Rattle Brook	15
7	**Total Power Purchases**	**1,031**
8	NLH standby generation	
9	GTs and CTs	11
10	Diesels	0
11	**Total Standby Generation**	**11**
12	Total Island Supply Requirement	7,239
13	Less Total Non - Holyrood	(5,646)
14	**Holyrood Energy Requirement**	**1,593**

Therefore, the forecast 'Holyrood Energy Requirement' determines the test year quantity of No. 6 fuel to be consumed. The forecast cost of No. 6 fuel is a function of forecast fuel cost, volume of fuel consumed, and the fuel conversion factor.

The 2015 Test Year the price of fuel was estimated to be $93.32 per barrel. However, the forecast price of fuel has declined since the filing of the Amended Application. Hydro filed with the Board on October 28, 2015 an updated fuel price projection for 2016. The revised 2015 Test Year forecast No. 6 fuel cost per barrel reflecting the 2016 forecast fuel price is $64.41 ($Cdn).

This cost is based on an average of the forecast 2016 No. 6 fuel price of $69.40 per barrel ($Cdn)[138] and the forecast 2015 year-end average inventory cost of $55.35 per barrel ($Cdn). Hydro submits that the cost of $64.41 per barrel of No. 6 fuel should be used by the Board when setting rates that come in effect in 2016 as this price reflects Hydro's most recent forecast cost.

No. 6 Fuel: Effect of Hydrology

The volume of fuel used at Holyrood is a function of the level of hydrology forecast. Hydro's forecasted hydraulic production was agreed to by all parties in the Settlement Agreement. Hydro proposes the Board accept this level of hydraulic production for the purpose of setting rates in 2016.

No. 6 Fuel: Conversion

The forecast of Holyrood fuel consumption, and ultimately Holyrood production costs, is affected by the energy conversion factor for a barrel of No. 6 fuel. The Board, in 2007, set this conversion factor at 630 kWh per barrel of No. 6 fuel consumed.[139] Since that time, Hydro has never achieved the fuel conversion rate of 630 kWh/bbl. In fact, during this period, with the exception of 2008, Hydro has not achieved a fuel conversion factor greater than 614 kWh per barrel.[140] To the extent that the actual fuel conversion factor has been lower than the 2007 Test Year level, the additional Holyrood production costs have been borne by Hydro.

Mr. P. Bowman on page 27 of his pre-filed evidence, dated June 4, 2015 states:

> *In short, by using the average station service rate from the past five years, a period of load which is not representative of the Test Years, the station service*

[138] The forecast No. 6 fuel price of $69.40 per barrel differs from the $69.15 per barrel provided in the IIC RSP fuel rider calculation filed October 15, 2015 because the forecast fuel price for 2016 is based on a forecast conversion rate from $US to $Cdn and the fuel price in the fuel rider calculation requires the use of a historical conversion rate based on approved RSP rules.
[139] See Order No. P.U. 8(2007).
[140] See hydro's Amended Application, Section 2, Schedule V, Page 1 of 1.

estimate as a percentage is too high. It is also apparent that Hydro has not given full consideration to providing ratepayers with the benefits arising from the capital projects. On this basis, a material downward adjustment in the station service, to yield a net efficiency improvement of 15 kW.h/bbl (8 kW.h/bbl for capital investment, plus 7 kW.h per bbl for a better regression of station service projected levels), to 622 kW.h would be appropriate.

Mr. P. Bowman has proposed two adjustments to Hydro's proposed fuel conversion rate of 607 kWh/bbl: (i) an adjustment of +7 kWh/bbl for a change in the approach for determining the level of Holyrood station service; and (ii) an adjustment of +8 kWh/bbl for the installation of new variable frequency drives on the unit forced draft fans.

Excluding the new capital improvements, Mr. P. Bowman has proposed a conversion rate of 614 kWh/bbl.[141] Hydro submits that the historical performance of the HTGS in recent years (since 2010 in particular) has been nowhere near this level, per Table 2.21 on page 2.75 of the Amended Application:

Table 3

Holyrood Fuel Conversion Performance and Hydro Financial Impact 2009 - 2014

	2009 Actual	2010 Actual	2011 Actual	2012 Actual	2013 Actual	2014 Forecast
Fuel Consumption ('000 bbls)	1,534.7	1,363.2	1,469.2	1,428.3	1,611.0	2,334.5
Actual Fuel Conversion Rate (kWh/bbl)	612	589	603	599	594	588
2007 TY Fuel Conversion Rate (kWh/bbl)	630	630	630	630	630	630
Hydro's Financial Loss ($ million)	2.4	4.9	3.5	3.9	5.1	8.8

This deterioration in performance continues in 2015, with Hydro forecasting a fuel conversion factor of 597 kWh/bbl.[142] While Mr. P. Bowman has proposed a different approach for

[141] 607 kWh/bbl + 7 kWh/bbl.
[142] See Schedule 3, Appendix D of Hydro's Amended 2015 Cost Deferral Application.

determining the station service factor used in calculating the net fuel conversion rate in 2015; it ultimately remains another approach, and one which does not lead to a reconciliation with Hydro's actual fuel conversion performance from the past seven years.

With respect to the +8 kWh/bbl that Mr. P. Bowman has forecasted for the new capital improvements at the HTGS, Hydro submits that this level of improvement, in relation to the average Holyrood unit loading forecast for the test year, is overstated. Mr. Goulding, for Hydro, in his testimony stated:

> *Yes, and although the preliminary data says this load point does indicate savings of 7 to 8 kilowatt hours per barrel, from a test year perspective it would have to be lower because we're going in with a higher average loading, and the analysis that we've done, and again it's very limited at this point, is that the benefit is in the order of 4 to 5 kilowatt hours per barrel.* [143]

Hydro submits that if this improvement were to be included in the forecast fuel conversion factor for 2016, a level of +4 kWh/bbl would be more appropriate than the +8 kWh/bbl as suggested by Mr. Bowman.

Hydro submits that the 607 kWh/bbl proposed in the test year is appropriate for setting rates in 2016. While this fuel conversion rate does not take into account the +4 kWh/bbl due to the new variable frequency drives, the historical conversion rate shows there is greater risk of achieving a lower conversion rate than a higher one.

Hydro submits that approval of the Holyrood Conversion Deferral to capture variances in the HTGS conversion factor would ensure that neither Hydro nor customers are advantaged or disadvantaged by changes in the fuel conversion factor between test years. This matter is dealt with in Section D.4.1.3.

[143] October 21, 2015 Transcript, pages 120, line 23 to 121, line 6.

Power Purchases

Hydro purchases power and energy from other suppliers to meet Hydro's customers' requirements on the Island Interconnected System. Power purchase expense included in the 2014 and 2015 Test Years is $60.3 million and $57.4 million respectively.[144] Included in power purchase expense are costs associated with capacity assistance agreements.

The primary reason for the increase in power purchases costs relative to the 2007 Test Year is due to the addition of wind and Exploits power. These power purchases have benefited customers through reduced HTGS fuel requirements. Hydro submits these power purchases are reasonable and the associated costs should be included in the 2015 revenue requirement.

Liberty, in its review of prudence issues dated July 5, 2015, stated that the CBPP Capacity Assistance Agreement for 2014 made "…a major contribution to system reliability…" and that "[t]here is therefore no reason for Liberty to challenge the prudency of that agreement".[145]

Hydro also entered into capacity assistance agreements with CBPP and Vale prior to the 2014-15 winter season. Hydro made a total of three requests for capacity assistance during the 2014-2015 Winter Period. These capacity requests helped to maintain generation reserves and, in the case of the March 4, 2015 events, lessened the outage impact on customers.

Hydro submits that the Capacity Assistance agreement costs for the 2014 and 2015 Test Years benefit customers and should be approved for inclusion in Hydro's revenue requirement.

Gas Turbine and Diesel

Hydro operates a number of gas turbines and diesel units on the Island Interconnected System, which provide additional long term generation capacity and increased generation reserves. The

[144] Section 2, Regulated Activities, Schedule VI, Page 1 of 1.
[145] Liberty Consulting, Review of Prudence Issues, Dated July 6, 2015, Page 20.

cost of diesel and gas turbine fuel has been included in the 2014 and 2015 Test Years at $6.4 million and $3.6 million respectively.[146]

Included in these forecast fuel costs for 2015 is the cost of operating the new Holyrood CT. In contrast to forecast production levels included in the 2015 Test Year, Hydro has been running the Holyrood CT at minimum output levels during peak periods of the day to provide enhanced system reliability. This operational practice began in 2015 in response to enhanced reliability assessments following the March 4, 2015 outage event, and has resulted in increased fuel consumption at the Holyrood CT relative to the 2015 Test Year forecast. Hydro submits that the cost of Island Interconnected gas turbine and diesel fuel be approved in conjunction with the proposed Energy Supply Account so that Hydro has the opportunity to recover prudently incurred supply costs on the island interconnected system.

Isolated Systems Supply Costs

The primary source of power supply for Hydro's isolated systems throughout the Province is diesel generation. The cost of diesel and gas turbine fuel has been included in the 2014 and 2015 Test Years at $23.2 million and $21.9 million respectively.[147]

Hydro, in its letter to the Board dated October 28, 2015, provided an updated 2015 Test Year forecast cost based on the most recent cost of diesel fuel of $20.0 million. No issues were raised by any party to the hearing with respect to these costs. Hydro submits that these items should be accepted for inclusion in revenue requirement by the Board.

Labrador Interconnected Supply Costs

The majority of all energy consumed on the Labrador Interconnected System is purchased from CF(L)Co. Power purchase costs from CF(L)Co are forecast to be $2.1 million and $1.9 million for 2014 and the 2015, respectively. No issues were raised by any party to the hearing with respect

[146] Section 2, Regulated Activities, Schedule V, page 1 of 1.
[147] Section 2, Regulated Activities, Schedule VIII, page 1 of 1.

to these costs. Hydro submits that these items should be accepted for inclusion in revenue requirement by the Board.

D.2.2.3 Financing Costs

- ***The debt guarantee provides substantial value to customers. The level of the debt guarantee fee payments are reasonable and are provided in response to a Government directive.***
- ***The timing of the RSP Surplus disposition in 2016 is currently uncertain. No adjustment to Hydro's 2015 Test Year financing cost is necessary.***

General

Hydro's 2014 Test Year interest expenses are $89.7 million and Hydro's 2015 Test Year interest expenses are $89.2 million. The 2014 Test Year interest expense is $13 million less than the 2007 Test Year; the 2015 Test Year is $13.5 million less.[148]

Three issues have arisen concerning Hydro's financing costs. Two concern Hydro's debt guarantee fee payments to Government:

- Is Hydro obligated to pay the fee; and
- Should it be apportioned, with only part of Hydro's payments recognized for rate-setting purposes.

Hydro's debt guarantee fee payments respond to a directive to Hydro from Government. The obligation argument is relevant only to the extent the Board has authority over rate recovery, and the Board should exercise that authority to allow recovery, as the Board has done consistently, because the fee is reasonable and provides direct benefits to ratepayers.

The Board should reject apportionment consistent with the findings reached by Hydro's financial advisor, Scotiabank.[149] The evidence promoting apportionment does not recognize

[148] Amended Application, Finance Evidence, page 3.17, Table 3.7, line 2.

the enhanced access to capital markets furnished by the guarantee and it rests on an overly narrow view of the time frame for assessing benefits.

The third issue centers on the interest accruing in Hydro's RSP accounts, hypothesizing an interest expense reduction Hydro might realize should the RSP accounts be paid out and the disbursed funds replaced with long-term debt. Hydro submits that this issue is premature, as it rests on decisions the Board has not yet been made concerning the disposition of RSP balances.

Debt Guarantee Fee: Basis for Payment

The debt guarantee fee is an annual fee Hydro pays Government in return for Government guaranteeing Hydro's debt obligations. The fee has been in effect for approximately 20 years, and for most of that time the fee equaled 1% of Hydro's outstanding debt obligations.[150] In 2008, as a means of temporarily improving Hydro's net income, the Government waived Hydro's requirement to pay the fee while continuing to guarantee Hydro's debt. This waiver continued until 2011 when the Government issued OC2011-218, directing that the fee be reinstated at a market rate of 25 basis points for short-term obligations and 50 basis points for long-term obligations.[151]

Hydro has always included its debt guarantee fee payments in its revenue requirement.[152] The Board always has permitted rate recovery, while acknowledging the debt guarantee's "fundamental importance" and "key role" in Hydro's overall financial condition and specific ability to access capital markets.[153]

[149] PUB-NLH-061, Attachment 1.
[150] Amended Application, Finance Evidence, page 3.31, lines 10-12.
[151] PUB-NLH-058, Attachment 1, paragraph ii. Short-term obligations have a term to maturity of ten years or less; long-term obligations have a term to maturity longer than ten years.
[152] Amended Application, Finance Evidence, page 3.31, lines 12-13.
[153] November 16, 2015 Transcript, Page 16, lines 7-23 (quoting from Order No. P.U. 7(2002-2003) page 35, and Order No. P.U. 14(2004) page 29. See also Amended Application, Finance Evidence, page 3.31, line 13.

Hydro pays the debt guarantee fee (and has reflected payment in the 2014 and 2015 Test Years) because Government, has directed Hydro to do so.[154] NP questioned whether OC2011-218 imposed a legal obligation to pay, since the statutory requirement to pay was not carried forward when the Hydro Corporation Act, 2007[155] repealed and replaced the previously governing, 1990 statute.[156]

Hydro's position is that paying the debt guarantee fee is justified because doing so complies with a stated Government policy — OC2011-218 — and because the fee is a fair exchange for the benefits debt guarantee provides to Hydro's customers.[157] Mr. Pelley testified that the Board should grant recovery of the debt guarantee fee because of the guarantee's continuing importance to credit market access. Further, Scotiabank's independent analysis confirmed that Government's new fees (fees much lower than those previously approved by the Board) were reasonable.[158]

Debt Guarantee Fee: Apportionment

Grant Thornton for the Board did not take issue with how Scotiabank measured the reduction in yield spread approach to measuring the value of the debt guarantee,[159] but criticized Scotiabank for not apportioning the cost savings by comparing these spreads to the fees Hydro pays to obtain them.[160] Scotiabank found that for short-term debt, the cost savings attributable to the Government guarantee averaged between 31.7 and 33.0 basis points ("bps"). According to Grant Thornton, a complete analysis would compare these savings to what Hydro would have to pay Government to obtain them. Of the 31.7 to 33.0 bps reduction in short-term yields, Hydro would be returning between 76 and 79 percent to Government via the 25 bps debt guarantee fee. For long-term debt, the yield spread was 35.6 to 47.8 bps, so in

[154] In accordance with OC2011-218.
[155] SNL 2007, c H-17.
[156] Id., section 40, repealing Hydro Corporation Act, RSNL 1990, c H-16.
[157] NP-NLH-254.
[158] November 16, 2015 Transcript, pages 15, line 18 to 17, line 13; and pages 73, line 11 to 82, line 3.
[159] Grant Thornton Report on 2013 Amended General Rate Application, June 12, 2105, page 19, lines 22-24.
[160] November 16, 2015 Transcript, page 96, lines 2 to 11; pages 175, line 12 to 176, line 25 and Grant Thornton Report on 2013 Amended General Rate Application, June 12, 2015, page 20, lines 16-18.

Grant Thornton's view the 50 bps debt guarantee fee would more than exceed the savings it would generate.[161]

Grant Thornton's apportionment analysis does not to account for a central benefit of Government's debt guarantee: market access. Government utilities across Canada benefit from the creditworthiness of their respective government by either obtaining a debt guarantee which is recovered through rates (Québec), or by borrowing directly from their provincial governments (British Columbia, Ontario, Manitoba). These provinces either extend guarantees or borrow funds on their utilities' behalf because credit markets view governments as among the most creditworthy of counter parties.[162] As Scotiabank observed, governments and those with government guarantees can access capital markets when others cannot, and they can do so on more flexible terms:

> *There are two additional features of a Guarantee has that are very difficult to value, namely; that during periods of stress in the credit markets, a guarantee from a government entity provides for unrestricted market access and that a guarantee allows for more flexibility as to maturity.*[163]

The benefits of access may be hard to quantify, but the value of this central feature of Canadian utility financing and regulation cannot be denied.

Grant Thornton inferred that for long-term debt Government's 50 bps fee is too high because the basis spreads they examined were less than 50 bps for the period. This inference does not recognize the value of enhanced market access and increased flexibility; it also implies the period it examined captures all market conditions. As Mr. Pelley testified, yield spreads fluctuate over time:

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[161] Grant Thornton Report on 2013 Amended General Rate Application, page 20, lines 7-15.
[162] November 16, 2015 Transcript, pages 13, line 14 to 14, line 24; pages 82, line 4 to 90, line 22.
[163] PUB-NLH-061, Attachment 1, page 6.

> *[O]ne thing I recognize is the basis point spreads that [Grant Thornton is] quoting here are based on looking at the market over a certain period of time. That's not to say that if we expanded that window, that there's not times that those spreads are probably 70 or 80 basis points or 100. If you look at it over a long cross-section of time, such that, you know - like, all you're trying to do is say - you're trying to look at a period of time and say what's reasonable.*
>
> *Okay, you know, they're quoting here 35.6 to 47.8, and all they're saying from that is in their view, based on that, 50 is not unreasonable, but from my position, I'm not concerned that 50 is too high for the reason I just gave. These spreads fluctuate over time. There will be times when actually your long term, let's say, your greater than ten year spread to your question, may be less than 50 basis points, in which case the fee - I don't want to describe it this way, but you could say "too high", but then there would be other periods of time where the spreads could be 70 or 80 basis points. So you're trying to capture a concept that's fluctuating in time with a single number. There's always going to be some discrepancy.*[164]

Government started imposing the debt guarantee fee approximately 20 years ago,[165] and the Board has consistently recognized that the guarantee provides value to ratepayers.[166] The benefits have not changed, and with the market-based fee, the cost of the guarantee has fallen substantially. Hydro's 2014 Test Year includes a debt guarantee payment of $3.7 million, $5.3 million less than the fee would have been under the previous, 1% requirement. For the 2015 Test Year, Hydro's payment is $4.4 million, $7.5 million less than the previous 1% requirement.[167] Hydro sees no reason for apportionment.

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[164] November 16, 2015 Transcript, pages 94, line 3 to 95, line 5. See also November 19, 2015 Transcript, pages 28, line 3 to 29, line 6.
[165] Amended Application, Finance Evidence, page 3.31, lines 10-12.
[166] November 16, 2015 Transcript, page 16, line 5 to page 17, line 2.
[167] Amended Application, Finance Evidence, page 3.32, lines 7-11.

RSP Interest

Hydro's 2014 Test Year interest expenses include $18.2 million of interest on Hydro's RSP balances; the 2015 Test Year includes $12.4 million.[168] Per the RSP rules, interest on RSP balances accrues at Hydro's WACC. For the 2014 Test Year, Hydro's WACC, also equal to Hydro's return on rate base, is 7.12%; for the 2015 Test Year, the WACC is 6.82%.[169]

Comparing Hydro's total capital for financing rate base against the combination of sum of Hydro's mid-year rate base plus capital work in progress, Mr. P. Bowman for the IICs hypothesizes that the RSP balances are functioning as an additional form of capital financing for Hydro, bearing interest at Hydro's WACC. Mr. P. Bowman then speculates that upon refunding the RSP balances Hydro will substitute these funds with long-term borrowing at a significantly lower rate,[170] resulting in immediate savings to Hydro.[171]

When the IICs asked Hydro how it was going to finance the refund of the NP surplus, Hydro responded, "As this matter has not yet been ruled on by the Board, no decision has been made with regard to financing."[172] Hydro still considers the timing of the RSP Surplus disposition to be uncertain.

D.2.2.4 Productivity and Cost Management

- ***By instituting a shared services model, Hydro has improved productivity and efficiency to the benefit of customers through more effective use of its employees.***
- ***Hydro has demonstrated a corporate culture that emphasizes cost consciousness and efficient operations.***

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[168] Amended Application, Finance Evidence, schedule I, Page 10, line 2.
[169] Amended Application, Finance Evidence, page 3.17, line 7 (Table 3.7).
[170] As of November 20, 2014, Hydro estimated its marginal cost of long-term debt at 3.558%. Grant Thornton Report on 2013 Amended General Rate Application, page 17, line 18 to page 18, line 2 (referencing PUB-NLH-53 (Revision 1)).
[171] Pre-Filed Evidence of P. Bowman and M. Najmidinov, pages 28-29; Ex. 2, pages 11-12; and September 30, 2015 Transcript page 100, lines 7-17 and pages 108, line 12 to 111, line 2.
[172] IC-NLH-054, lines 7-8.

- ***A productivity allowance is not warranted because Hydro has achieved meaningful productivity gains. Inflation provides an implicit productivity allowance as the 2015 Test Year is being used to set rates for 2016.***

Since 2007, Hydro's operating labour costs have increased by just 0.01 cents per kWh (one one-hundredth of a cent) on an inflation-adjusted basis, from 0.83 cents per delivered kilowatt-hour in 2007 to 0.84 cents per delivered kilowatt-hour in the 2015 Test Year.[173] This has been achieved while Hydro has been forced to manage cost pressures in areas that have a significant impact on Hydro's overall costs.

Hydro's evidence explains many specific areas where additional productivity and efficiency have been achieved. The shared services model is an example of measures that have been implemented to improve productivity and efficiency. As a result of the shared services model, employees are utilized in the most effective manner, which works to the benefit of Hydro. Another example is work planning and scheduling. Hydro identified this as an area in which efficiency improvements could be made and it has implemented changes to work scheduling, as well as execution, in order to be more efficient in its asset management and maintenance.[174]

Furthermore, in the context of elaborating on actions taken by Hydro that contain the growth of the Rural Deficit, Hydro provided evidence of numerous Hydro-wide cost control initiatives.[175] While Hydro-wide "Initiatives with Rural Deficit Impacts"[176] do indeed limit the growth of the Rural Deficit, they are measures that more generally result in cost savings and tend to increase Hydro's productivity and efficiency. As well, in addition to the initiatives that were explained in the context of the Rural Deficit, Hydro's evidence provides examples of many other cost saving initiatives.[177]

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[173] CA-NLH-328, page 2.
[174] September 23, 2015 Transcript, pages 133-136 and 145.
[175] NP-NLH-098 (Revision 1, Dec 9-14).
[176] NP-NLH-098 (Revision 1, Dec 9-14), Attachment 1.
[177] NP-NLH-057 (Revision 1, Mar 23-15).

The Consumer Advocate's questions about some of Hydro's specific productivity success stories touched on whether the measurable financial outcomes of certain initiatives are of a relatively small magnitude.[178] However, Hydro would be remiss if, in its efforts to find productivity gains, it were to ignore potential gains that are individually of a relatively small size. Hydro focuses on finding least-cost ways to provide safe and reliable service and does not dismiss potential productivity gains simply because their magnitude may be perceived to be small. The cumulative effect of small savings is meaningful and reduces overall costs to customers.

Hydro managers are responsible for ensuring work is being done as efficiently as possible. Each manager is responsible for a budget and generally, there is a financial person to support management of cost control.[179] As Mr. R. Henderson explained in this extended exchange with the Consumer Advocate, cost control at Hydro is not something to be relegated to specified individuals or directives; rather, cost control is a central element of Hydro's culture that permeates activities throughout the organization:

> *JOHNSON, Q.C.:*
> *Q. And can you explain how Hydro identifies efficiency initiatives within its organization?*
>
> *MR. HENDERSON:*
> *A. What we do is through again the budgeting process, through our planning process in which we develop our five year strategic plan as a key input, we look at that to identify initiatives that we could undertake to make us more efficient. So through that strategic planning process, we would be looking at what we will be doing in terms of improvements on a continuous improvement basis, and then through the budgeting process, we would establish that as well with monitoring what goes forward in the budget in trying to keep costs within inflationary pressures, to try to stay within what is expected inflation, and that's done*

[178] September 23, 2015 Transcript, pages 144-145.
[179] September 23, 2015 Transcript, pages 135-137.

through the budgeting process. So through that, you drive actions to try to bring out efficiencies.

JOHNSON, Q.C.:
Q. Mr. Henderson, to your knowledge, has made, I mean, a directed effort to identify efficiencies, or as Mr. O'Brien put it, to try to do more with less? I mean, a directed effort to identify such efficiencies within Hydro? Are you aware of any such directed effort?

MR. HENDERSON:
A. In terms of directed efforts, what we would be doing is through that budgeting process, through our work execution, looking at our long term asset plans, is looking for least cost solutions to everything that we do. So that would be part of looking at each capital proposal, any efficiency gains would be sought through that, so it's through a number of different avenues. There isn't a one subscribed "this is an efficiency improvement program", it's expected each and every manager is working to establish their work to be done in the most efficient manner. That challenge occurs through the strategic planning process, it occurs through the budgeting process, to ensure that those types of things are done.

One area that we've been focusing on, in particular, and I think I may have spoken to Mr. O'Brien about that, is the work scheduling and planning area where we feel that there is gains to be made there that we're setting out objectives there to improve the amount of work that we complete in terms of work execution, which is all around asset management and maintenance to get more done, and to schedule it efficiently so that the cost to that annual maintenance work is at the least cost.

JOHNSON, Q.C.:
Q. But, I guess, it's - what you've explained to us in terms of what you do is not part of a directed effort, and, I guess, you would agree that what you've done and what you've described has led to a circumstance where costs have outstripped inflation by about 30 odd percent, right?

MR. HENDERSON:
A. There's a number of things that are happening within the company related to the condition of our facilities, the aging of our assets, our capital investment program, the environment in which we work, our employees work, all of those items are putting upward cost pressure certainly to Hydro, and that we seek to manage those as efficiently as we can.

JOHNSON, Q.C.:
Q. Well, as part of seeking to manage them as efficiently as you can, can you explain why a directed effort has not been made? I mean, we talked about organizational excellence and, you know, high cost controlled environment. Can you explain why a directed effort has not been given, given the importance of identifying efficiency initiatives?

MR. HENDERSON:
A. Well, we have done a number of things over the3 years to look for those types of things, and we continue to look for those initiatives. To establish, I'll say, a separate initiative to pull people out of their jobs and go at that, we've opted not to do it that way, we do it through each manager who's expected to do that in their own work environment to ensure that they're doing it as efficiently as possible. We, as I said, work planning and scheduling was one area that we felt from an operations standpoint we can make improvements and are embarking

on that as a critical piece to do our work execution in terms of our asset management and maintenance more efficiently.

JOHNSON, Q.C.:
Q. So you indicated that you opted not to go the route of a directed effort. When was that decided upon?

MR. HENDERSON:
A. Well, I say that and it's somewhat - I'll say, it's by default, that we didn't do it. I mean, the way we are doing it and looking after our facilities, as I said, is through challenges to each of our managers to stay within inflation with their operating budgets.

JOHNSON, Q.C.:
Q. If I could ask you to go to 229. . . . Yes, Page 7 of 19. These are the general managers and managers who report to you, and I don't have to read them, they're there on the screen. Is any of your managers specifically tasked in their job description with cost control? Is there a go to manager on, you know, the cost controls within your organization?

MR. HENDERSON:
A. The cost controls, there are - in terms of cost controls and cost management, each manager has a responsibility, they have a budget that they have to manage. They have people in their groups - I think in almost every case there is a financial person that works alongside with them to help manage their budgets, help them to exercise the cost control that they need by providing them reports and data on how things are going relative to the budget, how they are managing their expenses.[180]

[180] September 23, 2015 Transcript, page 145.

Hydro has also included in the 2015 Test Year a challenging reduction in overtime expenses from historic levels.[181] Hydro has constrained 2015 operating overtime expenses even though it is experiencing growing and pressing requirements for overtime. Using 2013 overtime costs as a point of comparison - since those costs were not affected by the January 2014 outage - actual costs in 2013 were $12.3 million, while Hydro has reduced overtime costs to $10.1 million in the 2015 Test Year.[182]

Hydro aims to reduce its overtime costs through redeployment of staff and recruitment initiatives.[183] Because the achievement of this challenge has been assumed in the 2015 Test Year, there will be a negative impact on Hydro's income to the extent that the challenge is not met, while rates set on the basis of the 2015 Test Year will retain the benefit of the assumed overtime reduction.[184]

Another built-in productivity challenge relates to the timing of implementation of final rates for Hydro. Final rates will be based on a 2015 Test Year, but, given the timing of a Board decision, will not become effective until 2016. The lack of any adjustment to recognize the inflationary impact on costs from 2015 to 2016 effectively operates a productivity allowance for Hydro.[185]

Section D.3: Cost of Service and Rates

D.3.1 Settled Matters

D.3.1.1 Future Studies

There are a number of matters on cost of service and rate design to be addressed by the Board prior to the implementation of customer rates reflecting the costs of the Labrador-Island interconnection.[186] The rate-related matters include:

[181] CA-NLH-328, page 2.
[182] September 22, 2015 Transcript, page 97.
[183] September 23, 2015 Transcript, pages 165-171.
[184] CA-NLH-328, page 2.
[185] October 7, 2015 Transcript, page 106.
[186] Amended Application, Rates and Regulation Evidence, pages 4.4 - 4.6.

- A review of the embedded cost of service methodology;
- The completion of a marginal cost study and rate design review; and
- A review of Hydro's regulatory mechanisms for the recovery of supply costs.

Hydro has committed to filing a number of reports to permit the Board to conduct a comprehensive review of each of these items.

The Parties agreed the Board should in its Order direct Hydro to file:

(a) A marginal cost study no later than December 31, 2015;
(b) A cost of service methodology report no later than March 31, 2016;
(c) A report on the RSP and supply cost recovery mechanisms no later than June 15, 2016; and
(d) A GRA no later than March 31, 2017 for rate changes based on a 2018 Test Year.

The Parties also agreed a generic cost of service hearing should be held following the filing of the reports outlined in (a) to (c) above.[187]

D.3.1.2 Cost of Service Methodology

In the initial Settlement Agreement, the Parties agreed on the cost of service methodologies in Exhibit 13 (2015 Test Year Cost of Service) with respect to functionalization, classification and allocation, subject to nine exceptions:[188]

(a) The treatment of the curtailable load of NP;
(b) The classification of wind energy purchases;
(c) The classification of all Holyrood fuel costs;
(d) NP's load factor;
(e) The specific assignment of the frequency converter to CBPP, the calculation of that charge and any credit in the Cost of Service study associated with the frequency converter;

[187] Settlement Agreement, paragraph 23.
[188] Settlement Agreement, page 3, paragraph 13.

(f) The calculation of the capacity factor for the HTGS;
(g) The allocation methodology for the Rural Deficit;
(h) The basis on which specifically assigned charges to customers is calculated; and
(i) The use of the forecast 2015 load for rate-setting purposes.

Items (a) through (f) were resolved in the Supplemental Settlement Agreement.[189] Items (g), (h), and (i) were contested in the current GRA requiring those matters to be decided on by the Board.

In the Supplemental Settlement Agreement, the Parties also agreed on the requirement and the scope of a Cost of Service Methodology Review to be completed in 2016:

> *The Cost of Service Methodology Review to be completed in 2016 will include a review of: (i) all matters related to the functionalization, classification and allocation of transmission and generation assets and power purchases (including the determination whether assets are specifically assigned and the allocation of costs to specifically assigned assets) and (ii) the approach to CDM cost allocation and recovery.*[190]

All Parties agreed that with respect to the new cost items in the current GRA, the Board should approve that (i) wind purchases be classified as 100% energy-related and (ii) the costs associated with Hydro's capacity assistance agreements with Vale and CBPP shall be treated as production demand-related and allocated to each class of service based on a single coincident peak allocator.[191] With the exception of the allocation of (i) the Rural Deficit and (ii) operating

[189] Supplemental Settlement Agreement, page 2, paragraphs 7(a)-(e) and 8.
[190] Supplemental Settlement Agreement, page 3, paragraph 13. For further discussion of the cost of service examination, refer to Settlement Agreement, page 5, paragraph 23.
[191] Settlement Agreement page 3, paragraph 14(b). This settlement provision is agreed to notwithstanding the generality of the parties' agreement with the functionalization, classification and allocation contained in Hydro's COS Study.

and maintenance costs to specifically assigned assets, the Parties have agreed that the existing cost of service methodology be maintained consistent with the last GRA.

D.3.1.3 Cost of Service Data for KPI Reporting

The Parties also agreed Hydro should continue to report functionally oriented KPIs as required by the Board in Order No. P.U. 14(2014); however, such reporting will be based on the most recent Test Year Cost of Service study that is approved by the Board and not on a forecast basis.[192] The agreed approach reduces the administrative requirement to complete a Cost of Service study annually to support KPI reporting.

D.3.1.4 Rates and RSP Issues

The initial Settlement Agreement and the Supplemental Settlement Agreement provided agreement on the following rates and RSP issues:

(a) The current rate design for IICs should continue to apply as Hydro proposed in the Application.[193]

(b) The rate design for NP will be determined using the following approach:

   (i) The demand charge will equal $4.75 per kW of billing demand;

   (ii) The end block energy rate will be determined based on the 2015 Test Year No. 6 fuel price divided by the 2015 Test Year Holyrood fuel conversion factor (both to be determined by the Board); and

   (iii) The approved 2015 Test Year revenue requirement not recovered through the demand change and the end-block energy charge will be used to compute the first block energy charge.[194]

(c) Hydro's wholesale rate will include a curtailable load credit as proposed in its Amended Application.

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[192] Settlement Agreement, page 4, paragraph 22.
[193] Settlement Agreement, page 3, paragraph 15.
[194] Supplemental Settlement Agreement, page 3, paragraph 10.

(d) If the load variation component is maintained as an element of the RSP, year-to-date net load variations for NP and IICs shall be allocated among the customer groups based upon energy ratios, with effect from the date to be determined by the Board.[195]

(e) The proposed CDM Cost Recovery Adjustment should be approved to provide for recovery of costs charged annually to the CDM Cost Deferral Account.[196]

(f) The generation credit agreement between Hydro and CBPP, which the Board approved on a pilot basis in Order No. P.U. 4 (2012), should be continued on a pilot basis at this time.[197]

(g) There shall continue to be an industrial wheeling rate with the specific rate to be calculated in accordance with the methodology proposed by Hydro as may be modified by the Board in an Order arising from the GRA.[198]

D.3.2 Remaining Cost of Service Issues

D.3.2.1 General

A cost of service methodology establishes the approach to use in the allocation of costs to be recovered from customers. Application of the cost of service methodology to the test year costs provides the amount of costs allocated to each customer class through customer rates. The current cost of service methodology was approved by the Board in 1993 subsequent to a cost of service methodology hearing.

At the current GRA, Hydro proposed cost of service approaches for new cost items (i.e., wind purchases and capacity assistance agreements) as well as changes to currently approved methodologies due to changing circumstances (i.e., Rural deficit Allocation and Holyrood capacity factor).

[195] Settlement Agreement, page 3, paragraph 16.
[196] Supplemental Settlement Agreement, page 3, paragraph 12.
[197] Settlement Agreement page 3, paragraph 19. The status of the agreement will be reviewed in the COS generic hearing referred to referred to in paragraph 23 of the Settlement Agreement.
[198] Settlement Agreement, page 4, paragraph 20. The status of the agreement will be reviewed in the cost of service generic hearing referred to in paragraph 23 of the Settlement Agreement.

As stated, Hydro will be filing a cost of service methodology review in 2016 which will deal with, among other items, cost of service issues arising from the Labrador-Island interconnection.

The initial Settlement Agreement and the Supplemental Settlement Agreement provided agreement on most cost of service methodology issues. The cost of service methodology items not agreed upon in the current GRA include the:

- Basis for the allocation of the Rural Deficit;
- Basis for the allocation of operating and maintenance costs to specifically assigned assets for the use in determining specifically assigned charges to IICs; and
- IIC load forecast to be used in the 2015 Test Year.

D.3.2.2 Rural Deficit Allocation

- ***In the interest of fairness, the Rural Deficit should be allocated based on revenue requirement.***

Background

In its original Application, Hydro used the Rural Deficit allocation approach approved in February 1993 as a result of the Cost of Service Methodology hearing.[199] In CA-NLH-166, the Consumer Advocate asked Hydro to comment on the fairness of the methodology. In conducting a fairness assessment, Hydro reviewed past statements of the Board with respect to the treatment of the Rural Deficit.

On page 84 of the 1993 COS Methodology Report, the Board provided guidance on assessing fairness for the Rural Deficit allocation when it stated:

> *Fairness cannot be assessed as due to the method used but instead we must assess fairness on the basis of the result, a shared burden among the classes of customers that is fair to all and not discriminatory.*

[199] For the origins of the mini cost of service approach, refer to Amended Application, Evidence page 4.7, footnote 5.

In Order No. P.U. 7(1996-97) following NP's General Rate Application, the Board stated[200]:

> *The matter of whether or not the transfer of the Rural Subsidy from Government to Hydro and then on to its customers is a tax or cross-subsidy between utility customers was debated before the Board and dealt with in its report entitled "Referral by Newfoundland and Labrador Hydro for the Proposed Cost of Service Methodology" in February 1993. The Board's conclusion in that Report was that the Rural Subsidy was not a tax, but a form of cross-subsidization even though it was in the extreme.*

In that same Order, the Board also stated:

> *The Board confirms its previous opinion in the February 1993 … that the Rural Subsidy is a form of cross-subsidization, and must be dealt with as all other expenses.*

No specific direction has been provided by Government on the methodology for allocation of the Rural Deficit other than to exempt Industrial Customers from subsidizing Hydro's Rural Customers.

This is the first GRA in which: (i) uniform rates are in place for customers on the LIS; and (ii) none of the Secondary Revenue Credit is applied to reduce the revenue requirement for the LIS.[201]

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[200] Order No. P.U. 7(1996-97), page 89.

[201] Rates for Labrador Interconnected customers did not reflect recovery of any of the Rural Deficit until September 2002. In 2002, approximately $5.0 million of the Rural Deficit was allocated to the LIS, but the impact of this initial allocation was largely offset by the application of a revenue credit of $3.7 million from secondary energy sales to CFB Goose Bay. In Order No. P.U. 7(2002-2003), the Board decided that the Secondary Revenue Credit should be applied to reduce the Rural Deficit, rather than being applied as a credit against the cost of service for the LIS. Because of the potential for large customer impacts as a result of this change, the Board required Hydro to propose a plan for implementation, in combination with a plan to implement uniform rates for Labrador City, Happy Valley-Goose Bay and Wabush. By 2011, the phase-out of the CFB Goose Bay Secondary Revenue Credit was been completed concurrently with the phasing in of uniform rates for Labrador Interconnected

Fairness Assessment

Hydro's review of the fairness of the Rural Deficit allocation methodology was based on the customer impacts of recovering the $64.1 million forecast[202] 2015 Test Year Rural Deficit from customers on the LIS and from customers of NP.

Table 4 provides a comparison of the Rural Deficit impact per customer under the existing method compared to an allocation based on revenue requirement and an allocation based on the number of customers served.[203]

Table 4

Average Annual Cost per Customer Comparison[204]

	Existing Method	Revenue Requirement Method	Number of Customers Method
Labrador Interconnected	$653.15	$207.60	$235.23
Newfoundland Power	$216.64	$236.46	$235.23
Difference	($436.51)	$28.86	$ –

Under the existing methodology, customers on the LIS would bear average annual Rural Deficit costs of $653.15, roughly three times more than the $216.64 that would be borne by customers of NP.[205]

The revenue to cost ratio for Labrador Interconnected customers in the 2015 Test Year under the existing methodology is 1.42, while the revenue to cost ratio for NP customers is 1.12.[206]

customers. See Amended Application, Rates and Regulation Evidence, page 4.14, footnote 21; NP-NLH-407 and October 5, 2015 Transcript, pages 161-164.

[202] Amended Application, Volume II, Exhibit 13, Schedule 1.2, Page 1 of 6, column 5, line 14.

[203] Amended Application, Rates and Regulation Evidence, page 4.10, Table 4.3.

[204] Total 2015 Test Year deficit allocated divided by number of customers on LIS and number of customers served by NP.

[205] Amended Application, Evidence, page 4.8, lines 12-18. As Hydro noted, "[t]he higher deficit allocation per customer is primarily related to the attributes of the Existing Methodology that provides for increased deficit allocation to the system with higher average energy usage." Amended Application, Evidence, page 4.8, line 18 to Page 4.9, Line 2. For documentation of Labrador Interconnected customer's higher average energy use, refer to Amended Application, Evidence, page 4.9, footnote 9.

The relatively higher allocation of the Rural Deficit to Labrador Interconnected customers than to NP customers occurs under the existing methodology primarily because higher average energy usage drives a greater allocation of the Rural Deficit. The higher average use for customers on the LIS primarily results from living in an area of the Province where the climate is colder.[207] Hydro believes that the existing methodology does not produce a reasonable sharing of the Rural Deficit between Labrador Interconnected customers and NP customers.

Fairness in rates is commonly assessed based on revenue to cost ratios. The use of revenue requirement as a basis of Rural Deficit allocation results in the revenue to cost ratio in the 2015 Test Year Cost of Service Study for Hydro Rural Labrador Interconnected Customers being equal to the revenue to cost ratio for NP (i.e., 1.13).[208] Use of revenue requirement as the allocator results in an average allocated annual cost per customer that that is slightly higher for NP customers than for customers on the LIS.[209]

Hydro also evaluated the use of the number of customers as the allocator. If an allocation based on the total number of customers is used, the average annual cost per customer of the Rural Deficit for Labrador Interconnected and NP customers is the same.[210] While this approach would eliminate the difference in average cost per customer between the customers of NP and on the LIS, the use of the number of customers as an allocator would create fairness concerns between classes on the same system.[211] If the Rural Deficit within a system was allocated on the number of customers, the vast majority of the Rural Deficit would be allocated to the Domestic class within each system because Domestic customers comprise the largest number of customers.

Hydro is proposing the Rural Deficit commencing January 1, 2014 be allocated by system, based upon revenue requirement. Hydro's proposed approach would allocate

[206] Amended Application, Rates and Regulation Evidence, page 4.9, Table 4.2.
[207] Amended Application, Rates and Regulation Evidence, page 4.10, lines 1-4.
[208] Amended Application, Volume II, Exhibit 13, Schedule 1.2, page 1, column 8, line 3.
[209] Amended Application, Rates and Regulation Evidence, page 4.10, lines 16-18 and page 4.10, Table 4.3.
[210] Amended Application, Rates and Regulation Evidence, page 4.10, Table 4.3.
[211] Amended Application, Rates and Regulation Evidence, page 4.11 and footnote 13, page 4.11.

on average an additional $19 per year to NP's customers. This represents an additional 0.7% increase for these customers.[212]

The revenue requirement methodology proposed by Hydro gives consideration both to the lower rates and higher usage of Labrador Interconnected customers, whereas the existing methodology focuses more on the lower rates and thereby shifts more costs to customers on the LIS.[213] The impact of Hydro's proposed methodology is that the Rural Deficit will comprise 8% of customer charges from NP's customers, and 12% of charges to retail customers on the LIS.[214] On an absolute dollar basis, NP customers on average would pay somewhat more than Labrador Interconnected customers,[215] but on the basis of percentage of revenue requirement the impact would be higher for Labrador Interconnected customers. Using the revenue requirement allocation method, the allocated cost per customer is $236.46 for customers of NP and $207.60 for customers on the LIS. This difference reflects 14% higher average cost to serve NP's customers.[216] Hydro submits that this is a fair overall result and is more reasonable than the outcome of the existing methodology.

Position of Intervenors

All of the expert witnesses who gave evidence on this issue, except for Mr. Brockman on behalf of NP, support a change from the existing allocation methodology. Mr. Greneman indicated that fairness in the allocation of the rural deficit is most equitably apportioned on revenues, which gives consideration to both of the revenue components (i.e., electricity rate and customer load requirements).[217]

Dr. Feehan for the Labrador Towns said that the current approach should be replaced by one that ensures a more equal outcome and one of the alternative methods that he proposed for

[212] October 9, 2015 Transcript, page 95, line 7 to page 96, line 11.
[213] October 5, 2015 Transcript, pages 198-199.
[214] October 5, 2015 Transcript, pages 199-200.
[215] Amended Application, Rates and Regulation Evidence, page 4.10, Table 4.3.
[216] October 6, 2015, Transcript, page 95, lines 17 - 24.
[217] NP-NLH-414.

consideration is comparable to one of the alternatives evaluated by Hydro.[218] Mr. D. Bowman for the Consumer Advocate indicated that allocation of the Rural Deficit on the basis of either revenue requirement or the number of customers is preferred over the current allocation methodology.[219] Mr. Raphals for the Innu Nation recommended a fresh look at the methodology for the allocation, as proposed by Hydro.[220] Dr. Wilson for the Board stated "[e]ither a revenue or per customer allocation would appear to be more equitable than the existing allocation."[221]

Mr. Brockman for NP appeared to consider Hydro's use of revenue to cost ratios in its fairness assessment as inappropriate. He indicated Hydro's approach was a "strange usage of revenue to cost ratios".[222] Hydro respectfully submits that Mr. Brockman's statement is perplexing. Hydro has presented the revenue to cost ratios to isolate the impact of the Rural Deficit on each customer group in the same manner in each GRA since 1990. Mr. Brockman has participated in most, if not all, of those proceedings.[223]
Mr. Brockman should recognize that the revenue to cost ratios for both NP's customers and the customers on the LIS are above 1.0 because the revenue to cost ratio for Hydro Rural Customers is 0.51.[224]

The revenue to cost ratios show the ratio of the revenues collected based on the test year forecast to the cost to provide service based on the allocation methodology approved by the Board. No other experts expressed concerns with the use of revenue to cost ratios in evaluating the fairness of the existing Rural Deficit allocation methodology. Hydro submits the revenue to

[218] Amended Application, Rates and Regulation Evidence, page 4.12, lines 6-11.
[219] Amended Application, Rates and Regulation Evidence, page 4.12, lines 13-19.
[220] Amended Application, Rates and Regulation Evidence, page 4.12, lines 21-23.
[221] NLH-PUB-007.
[222] September 29, 2015 Transcript, page 202, lines 21-22.
[223] Mr. Brockman's witness profile states that he has presented evidence on behalf of NP, concerning cost of service, rate design and least cost planning in Hydro's 1990, 1992, 2001, 2003 and 2006 general rate referrals, as well as in Hydro's 1992 generic cost of service hearing, the 1995 Rural Rate Inquiry and Hydro's 2009 and 2013 Applications concerning the RSP and Industrial Rates.
[224] Amended Application, Volume II, Exhibit 13, Schedule 1.2, page 1 of 6, column 8, line 14.

cost ratio provides valuable information to the Board in evaluating the fairness of the Rural Deficit.

Mr. Brockman believes the current allocation methodology is reasonable.[225] In the allocation of customer-related costs, the existing methodology effectively assumes there are more customers on the LIS than the number of customers served by NP. Mr. Brockman also considers this a reasonable approach.

Mr. Brockman states it is difficult to assess "fairness" in the allocation of the Rural Deficit. His difficulty appears to be because the Rural Deficit is not causally related to the customers responsible for funding it.[226] Because of the disconnect between the customers creating the costs and the customers that have to pay the costs, Mr. Brockman appears unwilling to consider revenue to cost ratios and customer impacts in evaluating the fairness of the Rural Deficit allocation methodology.

Summary

The Regulatory Framework provided in Appendix A of Order No. P.U. 8(2007) included the fundamental principles used by the Board as a guide to rational decisions. Hydro submits that fair cost apportionment and the end result are the regulatory principles that should be considered by the Board in assessing the fairness of the Rural Deficit allocation methodology. The Regulatory Framework provides the following description of each:

> Fair Cost Apportionment
>
> *Fairness of specific rates in the apportionment of total costs of service among the different ratepayers should be such so as to avoid arbitrariness, capriciousness, inequities or discrimination. Under this principle, customers in similar situations should be treated equally (horizontal equity), while those in different situations should be treated differently (vertical equity). This principle would not deny cross-*

[225] NLH-NP-022.
[226] NLH-NP-022.

> *subsidization of rates among customers of equal circumstances but such subsidization should not cause undue discrimination. The principle of horizontal equity (i.e. equals treated equally) is set forth in Section 73(1) of the Act which requires that "all tolls, rates and charges shall always, under substantially similar circumstances and conditions in respect of service of the same description, be charged equally to all persons and at the same rate, …". Furthermore, the aspect of undue discrimination also has statutory reinforcement in Section 3(a)(i) of the EPCA which declares it to be "…the policy of the province that the rates to be charged ………should be reasonable and not unjustly discriminatory."*
>
> End Result
>
> *In compliance with the legislation, the end result must be fair, just and reasonable from the perspective of both the consumer and utility.*

The Regulatory Framework also states that: "*[t]he Board has discretion to choose the approach to setting rates as long as it observes the legislation and sound utility practices.*" The Board has been provided no legislative direction on the Rural Deficit allocation methodology (other than the exemption of funding from the IICs). Therefore, the Board is required to adhere to sound utility practice in its determination of a fair approach to the apportionment of the Rural Deficit with the objective of achieving an end result which must be fair, just and reasonable from the perspective of both the consumer and utility.

Hydro submits that the existing Rural Deficit allocation methodology is not fair to Hydro Rural customers on the LIS. Hydro submits that the evidence before the Board in the GRA supports the use of revenue requirement as a fair and reasonable basis for allocation of the Rural Deficit in the cost of service methodology.

D.3.2.3 Allocation of O&M Costs to Specifically Assigned Assets

- ***Hydro's O&M costs attributable to specifically assigned assets should be allocated according to their relative value stated in constant 2015 dollars, rather than original cost.***

In the current cost of service methodology, the cost of capital assets that are used solely for the provision of service to a single customer are functionalized as specifically assigned. Specifically assigned costs are to be recovered from the customer for which the related assets provides service. There are currently transmission assets in service that are specifically assigned to IIC's. Customers are required to pay specifically assigned charges that recover the cost of return, depreciation and operating and maintenance costs for specifically assigned assets. For customers that paid a contribution for 100% of the capital investment, the specifically assigned charge would only recover the operating and maintenance costs. The specifically assigned charges are updated in each GRA Test Year.

In the 2015 COS study, direct O&M costs are classified/allocated based on the original cost of the plant in service (which is accounted for in the in-service year dollars). Administrative and General O&M expenses are classified/allocated based on a series of calculations using plant in service and direct O&M.

Mr. Dean argued that using original cost to pro rate O&M expense assigns too much cost to newer facilities, like the specifically assigned facilities constructed for Vale:

> *The prorating of O&M costs using plant in service without accounting for the time value of money has the potential to achieve inequitable results. This possibility is heightened with an electrical system consisting of new and old assets as one is comparing vastly different original costs. … As such, the total of Vale's plant in service measured in 2012 dollars is being prorated against plant in service values that are based on 1960's dollars.* [227]

[227] Pre-filed Evidence of Mr. Dean, June 4, 2015, page 10, line 16 through page 11, line 2.

To correct the situation, Mr. Dean argued that O&M apportionment should be based on assets valued in constant dollars.[228]

Hydro acknowledges that the existing methodology may not be ideal in allocating O&M costs to specifically assigned charges. This is because there is an inherent inverse relationship whereby older plant that cost less at the time of installation, generally requires more O&M than more expensive newer plant. [229] An alternate approach to the allocation of the direct transmission portion of O&M expense to specifically assigned charges is to use current dollars (2015 $) as a basis to reallocate the direct transmission O&M expense calculated in the 2015 Test Year COS study between specifically assigned charges and common.[230]

Based on its 2015 Test Year COS Study, Hydro calculated how much the O&M cost allocations to specifically assigned assets would change if the allocations were based on transmission assets values stated in constant 2015 dollars instead of original costs. The result of the analysis transferred approximately $600,000 of O&M costs from specifically assigned costs to common costs. The materiality of the customer impact of using current dollars rather than original costs as the basis for O&M cost allocation to specifically assigned assets supports Mr. Dean's position with respect to the concerns with the current approach.[231]

The use of the approach proposed by Mr. Dean is comparable to the method used by NP in determining the amount of O&M costs reflected in the cost factors that apply in determining CIAC from customers for distribution line extensions.[232] The CIAC cost factors reflect operating and maintenance costs based on a percentage of indexed asset costs.[233] This approach was

[228] Pre-filed Evidence of Mr. Dean, June 4, 2015, page 12, lines 3-5.
[229] V-NLH-083 (Revision 1, June 23, 2015), page 1, lines 17-24. October 6 Transcript, pages 58, line 12 to 59, line 1.
[230] See Amended Application, Volume II, Exhibit 13, Schedule 2.4A, Page 1 of 2, Col 5, Line 11 and Col 18, Line 11 for the total direct transmission O&M expense under the current COS methodology (i.e., $5,522,963 + $1,285,395 = $6,808,358).
[231] Undertaking No. 45.1, Attachment 1 includes an updated 2015 Test Year Cost of Service model which reflects the impacts of using the revised methodology for allocating specifically assigned O&M expense proposed in V-NLH-083 (i.e., reflecting indexed plant values).
[232] Response to V-NLH-125.
[233] The CIAC cost factors are submitted annually by NP for approval by the Board.

implemented following the 1997 hearing on the CIAC Policy and replaced the previous approach that was based on the use of original costs.[234] The contexts are different, but the reason for using indexed costs to allocate O&M costs is the same and supports Board approval of Vale's position on O&M cost allocation.

Hydro provided the 2015 Test Year COS Study reflecting the use of indexed asset costs for the purpose of allocation of O&M costs to specifically assigned assets. Hydro submits this approach provides a fairer result and should be adopted for the cost of service methodology in the current GRA. The Cost of Service Methodology review scheduled for 2016 will provide an opportunity to perform a more comprehensive review the overall approach to determining specifically assigned charges to the IICs. [235]

D.3.2.4 IIC Load Forecast for 2015 Test Year

- ***Hydro's proposed IIC rates are reasonable; normalization for expected industrial load is unwarranted.***

Hydro's proposed rates reflect the 2015 forecast load for the IICs in the 2015 Test Year. Mr. D. Bowman, expert for the Consumer Advocate, presented evidence that the rates derived for the 2015 load forecast for IICs are not just and reasonable. Mr. D. Bowman recommended that the Board adjust the test year to reflect loads during the 2015 to 2017 period.[236]

Hydro disagrees with Mr. D. Bowman's assessment. Mr. Fagan for Hydro stated:

> *The proposed firm demand rate and firm energy rate for IC, in combination with the operation of the RSP, are reasonable for recovering the cost of serving the IC class for the period 2015 to 2017. As the IC load increases, the new customers will pay increased demand cost as a result of their increased*

[234] October 6, 2015, Transcript, page 62, lines 7-9.
[235] October 6, 2015 Transcript, pages 78, line 15 to 79, line 22.
[236] Pre-filed Evidence of Mr. D. Bowman, June 1, 2015, pages 23-24. For Mr. D. Bowman's direct testimony on this issue, refer to September 30, 2015 Transcript, pages 21, line 25 to 24, line 16.

> *demand requirements. The customers will also pay increased energy charges based on the firm energy rate and the additional RSP charges to recover increased fuel costs due to their load growth.*
>
> *Normalization to reflect higher future loads in the allocation of the 2015 Test Year revenue requirement will result in reflecting the future cost of serving IC load in current rates. Allocation of a higher proportion of costs to Industrial Customers based on the 2017 forecast will have the effect of materially increasing the rates to be charged IIC and result in over-recovering the cost of serving Industrial Customers in both the test year and in future years.*
>
> *The load forecast reflected in the 2015 Test Year includes Vale and Praxair as high load factor customers and therefore no normalization is required.*[237]

The analysis provided in Undertaking No. 44 indicates that normalization to reflect higher future loads in the allocation of the 2015 Test Year revenue requirement will result in reflecting the future cost of serving IIC load in current rates. Allocation of a higher proportion of costs to IIC based on the 2017 forecast will have the effect of materially increasing the rates to be charged IIC and result in rates that over-recover the cost of serving IIC.

The presence of increased forecast load beyond 2015 for the IICs is not sufficient, in itself, to warrant normalization. Normalization is warranted only when the Test Year rates are anomalous and normalization will address the anomaly.

The load forecast reflected in the 2015 Test Year includes Vale and Praxair as high load factor customers and therefore no normalization is required. Hydro submits that the IIC load forecast used in the 2015 Test Year is appropriate for establishing reasonable rates.

[237] October 5, 2015 Transcript, pages 99, line 6 to 100, line 9.

D.3.3 Remaining Rates Issues

D.3.3.1 General

Hydro has not proposed material changes in customer rate designs in the Amended Application. The settlement agreements reflect a continuation of current rate designs for NP and the IICs pending conclusion of the planned studies discussed in Section D.3.1.1. These studies scheduled for completion over the next 12 months will provide updated information on marginal costs, cost allocation issues, rate designs and supply cost recovery mechanisms.

The Settlement Agreement and the Supplemental Settlement Agreement provided agreement on many rates issues. The rates issues not reflected in the agreements include:

- The continuation of the load variation component in the RSP;
- The disposition of the RSP load variation component balance that accumulated for the period September 1, 2013 to December 31, 2014;
- The deferred rate increases proposed to apply to Hydro Rural customers on Isolated Systems; and
- The proposed Labrador Industrial Transmission Rate.

D.3.3.2 RSP Load Variation Component

- ***The load variation component of the RSP should be maintained.***

The IIC load is forecast to grow materially in 2016 and 2017 because two new IICs are in the process of becoming fully operational (250 GWH cumulative load growth over 2016 and 2017).[238] The generation utilized to serve the IIC load growth between Test Years will be supplied by from Holyrood.

The cost incurred to serve this additional load based on the Amended Application is approximately 15¢ per kWh.[239] The additional energy revenues from IIC under the proposed rate are based on an energy rate of 5.151¢ per kWh. The load variation component in the RSP

[238] Undertaking No. 45.1
[239] Amended Application, Rates and Regulations Evidence, page 4.22, line 23.

allows Hydro to recover the net loss on sales growth to the IICs. For the period 2016 and 2017, the load variation permits Hydro to recover approximately $42 million in fuel costs that will not be recovered through the IIC base rate.[240]

Mr. P Bowman has recommended elimination of the Load Variation Component in the RSP.[241] However, Mr. P. Bowman also states "…it is conceivable that the best time to eliminate the provision is upon initiation of the Labrador infeed, in the event a lower incremental cost of power is incorporated into the purchase rates".[242] The Settlement Agreement provides for a review of all components of the RSP in 2016 in addition to a review of the IIC rate design. Hydro submits it is not appropriate to eliminate the RSP load variation component prior to the implementation of a new IIC rate design that permits reasonable recovery of the marginal cost to provide service to the IIC.

D.3.3.3 Disposition of the Balance in the RSP Load Variation Component

- ***The balance accumulating in the RSP load variation component that has accumulated since September 1, 2013, should be allocated among Hydro's customer groups based on energy ratios.***

In the Settlement Agreement, all Parties agreed that if the load variation component is maintained as an element of the RSP, year-to-date net load variations for NP and IICs shall be allocated among the customer groups based upon energy ratios, with the effective date to be determined by the Board.[243]

The amounts that accumulated in the RSP load variation component for the period 2007 to August 31, 2013 have been transferred to the RSP surplus for disposition in accordance with the Government directive. The forecast balance in the RSP load variation component as of

[240] The forecast load growth for IIC and the forecast RSP load variation component transfers are provided in Undertaking No. 44.
[241] Pre-filed testimony of P. Bowman and H. Najmidinov, June 4, 2015, page 47, lines 27 - 28.
[242] Pre-filed testimony of P. Bowman and H. Najmidinov, June 4, 2015, page 48, lines 19 - 21.
[243] Settlement Agreement, page 3, paragraph 16.

December 31, 2014 is approximately a $33 million credit to customers.[244] Hydro is proposing to allocate this balance based on an energy ratio allocation effective September 1, 2013, which would result in an allocation of approximately $31 million to NP and approximately $2 million to the IICs.[245]

Mr. D. Bowman for the Consumer Advocate recommended that "the Board order that the money that has accumulated in the load variation component of the Island Industrial Customer RSP account since September 1, 2013 be transferred to the RSP account of Newfoundland Power."[246]

Hydro disagrees with Mr. D. Bowman's recommendation. The use of energy ratios for allocation of fuel savings resulting from load variation balances that accumulated for that period is consistent with the manner that RSP fuel price variations were allocated in the RSP for that same period.[247] Therefore, Hydro submits that it is appropriate that the RSP rules related to the allocation of the load variation component be modified such that the year-to-date net load variation for both NP and IC is allocated among the customer groups based upon energy ratios effective is September 1, 2013.[248]

D.3.3.4 Implementation of the Deferred Rate Increase

- ***The Board should approve the proposed above average increases in customer rates for Hydro Rural non-Government Domestic and General Service customers on isolated systems.***

In the Amended Application, the proposed rate increases for Hydro Rural non-Government Domestic and General Service customers on isolated systems are higher than the average

[244] Per Order No. P.U. 29(2013), load variation is to be segregated in a separate account within the RSP.
[245] Load variations transfers for 2015 on an interim basis will need to be recalculated to reflect the approved 2015 Test Year rates and the 2015 Test Year fuel cost assumptions.
[246] Pre-filed evidence of D. Bowman, June 1, 2015, page 14, lines 12-15.
[247] Amended Application, Evidence, Section 4.71.
[248] The amounts that accumulated in the load variation component for the period 2007 to August 31, 2013 have been transferred to the RSP Surplus for disposition in accordance with the Government directive.

increase proposed for the Hydro Rural Island Interconnected customers. The proposed above average increases result from the combined effect of (i) the 2015 Test Year forecast change in rates for Island Interconnected customers and (ii) the increase in rates to implement the 2007 rate change that was deferred as a result of Government directives.

The non-lifeline portion of the Domestic energy rate[249] and both small and large general service diesel rates[250] were proposed to increase by 15% in 2007 to reflect the increased cost of fuel since the previous GRA. However, the 2007 proposed rate increase was not implemented in 2007 as a result of OC2006-512. Additional Government directives have been provided each year, which have continued to defer the 2007 rate increases. The most recent Government directive on this matter provides that in 2016 the customer rates shall be those that would have come into effect but for the Government directives.

Hydro submits that approval of higher than average increases for Hydro Rural non-Government Domestic and General Service customers is consistent with the Government directive on this matter.

D.3.3.5 Labrador Industrial Transmission Rate

- ***Hydro's proposed transmission demand charge for service to Labrador Industrial Customers should be approved.***

Hydro has proposed a transmission demand charge to be applied to Labrador Industrial Customers. The calculation of the demand charge is based on the portion of the transmission revenue requirement determined in accordance with the COS functionalization, classification and allocation methods previously approved by the Board.[251]

[249] For Domestic Customers, the 15% is applicable to only non-lifeline energy rates. The 2007 deferred rate increase for Domestic Customers would have resulted in an overall increase of 4%.
[250] Prior to 2007, there was no annual RSP adjustment reflecting the rate change to the customers of NP.
[251] Amended Application, Rates and Regulations Evidence, page 48.

Hydro notes that the Billing Demand definition in the proposed Labrador Industrial Transmission Rate does not address the treatment of Labrador Industrial interruptible load. Hydro will be filing an application in January 2016 to address this matter in the terms of the rate. This modification will not impact the calculation of proposed firm transmission demand charge based on the 2015 Test Year costs.

Hydro submits that the Board should approve the methodology used by Hydro to compute the proposed Labrador Transmission demand charge of $1.25 per kW per month.

D.3.3.6 Uniform Rates for Labrador Interconnected Customers

- ***The proposed uniform rates for Labrador Interconnected System customers are reasonable.***

In Order No. P.U. 7(2002-2003), the Board approved that Hydro develop a plan to phase-in uniform rates for customers on the LIS. The phase-in of uniform rates on the LIS was concluded in 2011. Prior to 2011, different rate schedules applied to customers in Labrador East and Labrador West.[252]

Mr. P. Raphals, the expert representing the Innu Nation, recommended that a rate rider should be considered to apply to customers in Labrador West due to the magnitude of the capital costs resulting from the Labrador City distribution upgrade.[253] This recommendation is effectively requesting the Board to reverse its decision on uniform rates that which was only recently implemented.

Hydro notes that in Order No. P.U. 7(2002-2003), the Board did not approve the proposal of the Labrador West customers requesting for Hydro to maintain a separate set of rates for Labrador

[252] Because of the potential large customer impacts of making this rate change, the Board required Hydro to propose a plan for implementation at its next rate hearing in combination with a plan to implement uniform rates for Labrador City, Happy Valley-Goose Bay and Wabush. The current GRA is the first hearing before the Board in which the Secondary Revenue Credit is fully credited to the Rural Deficit.
[253] Pre-filed Evidence of Philip Raphals, June 23, 2015, page 37.

West. The application of a single set of rates on the LIS is consistent with the use of a single cost of service study for the LIS, as approved by the Board. Hydro believes the evidence before the Board does not demonstrate that the uniform rate schedules proposed by Hydro result in rate discrimination to customers in Labrador East. Therefore, Hydro submits that Mr. Raphals' recommendation for a rate rider to apply to customers in Labrador West should be denied.

Section D.4: Supply Cost Rated Deferral and Recovery Mechanisms

D.4.1 Hydro's Proposed Supply Cost Related Deferrals

- ***Hydro should have a reasonable opportunity to recover supply costs prudently incurred in providing service to customers.***
- ***Receiving a government-directed ROE also does not justify denying or restricting Hydro's use of these accounts due to decreased business risk; the Canadian utilities with supply related deferral accounts often have target returns on equity higher than the 8.8% directed for Hydro.***

Hydro has proposed three new supply related deferrals in the Amended 2013 GRA:

- The Isolated Systems Energy Supply Cost Variance Deferral Account (Isolated Systems Deferral);
- The Energy Supply Cost Variance Deferral Account (Energy Supply Deferral); and
- The Holyrood Fuel Conversion Factor Deferral Account (Holyrood Conversion Deferral).

Recovery of supply costs through deferral mechanisms is common practice in regulatory jurisdictions across Canada.[254] Further, regulatory precedent also exists for the approval of such deferral accounts in the context of a government directed return on equity. Specifically, BC Hydro's return on equity has been set by a government directive and BC Hydro was subsequently granted approval by the BCUC for a deferral account to capture variances in non-

[254] PUB-NLH-388.

heritage supply costs.[255] Hydro submits that these precedents are supportive of the aforementioned deferral accounts proposed in the 2013 Amended GRA.

D.4.1.1 Isolated Systems Deferral

Hydro has proposed the Isolated Systems Deferral to capture variances from the 2015 Test Year in the cost of supplying customers on Hydro's Isolated Systems. Hydro's cost of supplying these customers is primarily based on the cost of diesel fuel.[256] Diesel fuel is a commodity and is priced based on market factors beyond Hydro's control. Since Hydro's 2007 GRA, the price of diesel fuel has experienced significant price volatility, as noted in the following chart found on page 3.47 of Hydro's Amended Application:

Chart 2

Diesel Fuel Price Variability

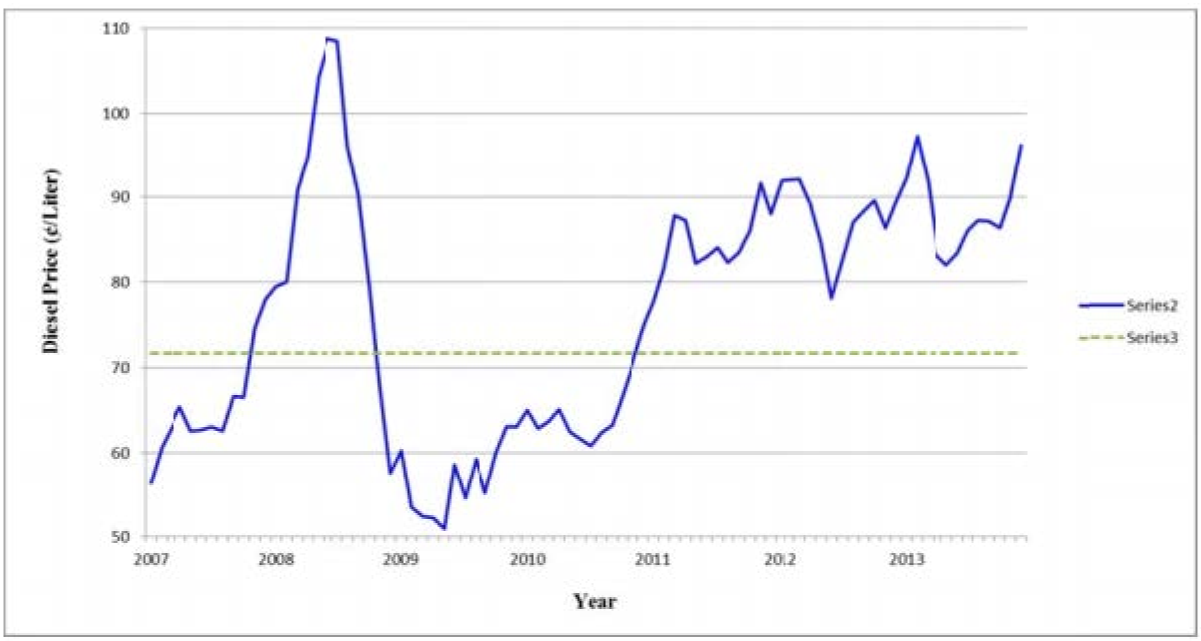


Chart 2 shows the level of volatility Hydro has experienced in the price of diesel fuel between test years. This level of risk has been material since the 2007 Test Year, is beyond

[255] November 18, 2015 Transcript, pages 114-120 as well as Undertaking No. 167.
[256] The Isolated Systems Account also captures variances in supply costs on isolated systems where costs are based on the price of diesel fuel.

management's control, and is appropriate to be dealt with through the proposed deferral account.

D.4.1.2 Energy Supply Deferral

Since Hydro's last GRA in 2007, Hydro has acquired a number of new supply sources. These new supply sources, including Exploits, wind generation, and the Holyrood CT have benefited customers either through increased reliability or reduced cost of service. However, variances in Hydro's now more broad supply mix can have a material impact on Hydro's financial results in a given year.

Without the proposed Energy Supply Account Hydro will be financially disadvantage as a result of: (i) variances beyond its control; (ii) providing greater reliability of service to customers and; (iii) economically optimizing the Holyrood CT in conjunction with the HTGS. These scenarios are discussed in detail below. Hydro submits that approval of this account is consistent with regulatory practice and in the best interest of customers and the utility.

D.4.1.3 Holyrood Conversion Deferral

Hydro has proposed a fuel conversion rate of 607 kWh/bbl for the purpose of setting base rates in the 2015 Test Year, a reduction from 630 kWh/bbl approved in the 2007 Test Year. Since 2007, Hydro has never achieved the 2007 Test Year conversion rate. In fact, the average conversion rate over this period has been 602 kWh/bbl.[257] Table 2.21 on Page 2.75 showed the financial impact to Hydro as a result of the variance in Holyrood Conversion Rate from the 2007 Test Year, which is shown below:

[257] Calculated as the simple average annual rate from 2007 through 2014 per Hydro's Amended Application, Section 2, Schedule V, page 1 of 4.

Table 5

Holyrood Fuel Conversion Performance and Hydro Financial Impact 2009 - 2014	2009 Actual	2010 Actual	2011 Actual	2012 Actual	2013 Actual	2014 Forecast
Fuel Consumption ('000 bbls)	1,534.7	1,363.2	1,469.2	1,428.3	1,611.0	2,334.5
Actual Fuel Conversion Rate (kWh/bbl)	612	589	603	599	594	588
2007 TY Fuel Conversion Rate (kWh/bbl)	630	630	630	630	630	630
Hydro's Financial Loss ($ million)	2.4	4.9	3.5	3.9	5.1	8.8

Table 5 shows that for five of the six years Hydro incurred additional fuel costs of $3.5 million or greater as a result of the reduction in the fuel conversion rate approved in the 2007 Test Year. Hydro notes that $3.5 million represents approximately 20 basis points in the range of return on rate base.[258]

The most recent estimate of Holyrood's conversion rate is 597 kWh/bbl, and the difference between this estimate and the conversion rate used to calculate the 2015 Test Year results in a $2.4 million revenue shortfall to Hydro.[259] Hydro, in the Amended Application, stated this deterioration of the conversion factor was due primarily to factors beyond Hydro's control. These factors include lower production requirements at Holyrood as a result of reduced system loads, higher energy purchases, and higher levels of hydraulic generation.[260] Hydro submits that the utility should not be at risk for material supply cost variances that are beyond its control.

Mr. P. Bowman, in his pre-filed evidence, states the creation of this deferral would be acceptable:

> *In addition, however, Hydro has proposed a new Holyrood Conversion Rate Deferral Account which means that ratepayers collectively will bear the costs of*

[258] Transcript, October 6, page 91, line 22 to page 92, line 4.
[259] Hydro's Amended 2015 Cost Deferral Application, page 1, Appendix D.
[260] Amended 2013 GRA, page 2.74.

> *whatever change in conversion factor arises in future compared to GRA levels, positive or negative. Such an account would normally be of concern as it relates to items reasonably within the utility's risk profile. However, for the current hearing given the transitional role of Holyrood, this approach may be accepted.*[261]

In addition to the factors affecting production levels at Holyrood, the BTU content of the fuel affects the conversion factor and therefore Hydro's costs. Mr. R. Henderson's in his testimony states:

> *The element here of this that people should be aware of is that we, from buying the fuel, we're buying BTU content which is what is the real heating value of the fuel to produce electricity. So we are paying for the BTUs. The problem for Hydro with this is that that fuel price variability goes into the RSP to customers. It does not come back to Hydro and Hydro suffers the consequence in a lower conversion factor and so, the manner in which the BTU -- the kilowatt hours per barrel number is fixed, but the BTU content varies. Hydro is taking that while it doesn't obtain any benefit, but the pricing improvement that you get by getting lower BTU falls out into the price of oil which goes through the RSP and benefits customers. So there's a disconnect, if you like, in terms of the benefit to customers versus the impact to Hydro.*[262]

Hydro has established in its No. 6 fuel supply arrangement a No. 6 fuel purchase price that can vary based on the BTU content of fuel delivered. This practice ensures customers are protected for changes in the BTU content of delivered fuel through the RSP. However, without the proposed Holyrood Conversion Deferral Hydro will continue to be financially disadvantaged for a lower BTU content as the conversion factor assumed in rates will not change with the actual BTU content of the fuel being consumed at the HTGS.

[261] Pre-filed evidence of P. Bowman dated June 4, 2015, page 3.
[262] Testimony of R. Henderson, September 23, 2015, pages 90-91.

D.4.2 Financial Incentives and System Optimization

- ***Hydro's proposed Energy Supply Deferral and the Holyrood Conversion Deferral foster system wide generation dispatching decisions that benefit customers through enhanced reliability.***

Hydro submits that approval of these proposed deferral accounts would provide Hydro with appropriate financial incentives to operate its system on a reliable, least cost basis. Further, they will ensure Hydro is not financially disadvantaged for optimizing the system for the benefit of customers.

D.4.2.1 Reliability

Hydro operates its generating plants to provide reliable service to its customers, by providing sufficient reserves to minimize impacts on customers for single contingency equipment outages. The growth in demand in recent years has resulted in a greater reliance on combustion turbines for this purpose. The addition of the Holyrood CT provides Hydro a greater ability to secure reliable operation for such contingencies. Hydro is currently operating the Holyrood CT to provide additional security of supply. This practice began after the events of March 4, 2015 and is consistent with Liberty's findings of the same.[263] A further example of this, presented to the Board during Hydro's GRA hearing, was the required annual planned outage of all units at the HTGS to complete common plant equipment maintenance. Having no units operating on the Avalon Peninsula exposes customers on the Avalon Peninsula to an outage in the event that a transmission line was forced out of service.

In the past, during the annual total plant outage at the HTGS, Hydro would keep the Hardwoods CT available if such a contingency occurred. The Hardwoods plant does not have sufficient capacity to cover completely customer load requirements, thus leaving some customers exposed to an interruption during a line out contingency. With the addition of the Holyrood CT, and in response to this interruption risk, Hydro has been running the Holyrood CT at minimum

[263] See Liberty Consulting's Report dated October 22, 2015, page 7, Section 2.

output levels during peak periods of the day to provide enhanced reliability. This operational practice began in 2015 in response to enhanced reliability assessments following the March 4, 2015 outage event.

Without the proposed Energy Supply Account Deferral, higher costs resulting from increased generation at the Holyrood CT to provide this higher standard of reliability would be borne by Hydro with no opportunity to recover the additional cost from customers. This scenario creates a financial disincentive for Hydro to operate the Holyrood CT in excess of the forecast test year levels, regardless of whether operation of the Holyrood CT results in more reliable service to customers. Hydro submits that approval of the proposed deferral accounts is consistent with the provision of reliable service to customers.

D.4.2.2 System Optimization

There are times when Hydro has the opportunity to optimize economically the operation of the Holyrood CT in conjunction with the HTGS.[264] A scenario where a unit at the HTGS can be brought offline for a week and the Holyrood CT is only used at peak times during that week can result in net fuel cost savings for customers through the RSP.[265]Without the proposed Energy Supply Deferral, Hydro would be negatively impacted financially for optimizing the system in this fashion, as the HTGS fuel savings would accrue inside the RSP and flow to customers while all additional CT costs incurred would be borne entirely by Hydro.

Hydro currently operates the Holyrood CT and HTGS to provide the most reliable, least cost service to customers. Hydro submits that approval of these supply deferrals will ensure Hydro is financially incentivized to provide least cost service to customers on a system wide basis, not just from specific supply sources.

[264] GRA Transcript, October 20, pages 132-136.
[265] GRA Transcript, September 23, 2015, page 98.

D.4.3 Intervenor Evidence

Two experts in their pre-filed evidence provided opinions against approval of the requested deferral accounts. Mr. D. Bowman for the Consumer Advocate and Mr. Wilson for the Board both opposed the creation of these deferrals in the context of Hydro's ROE.

Mr. D, Bowman, on page 5 of his pre-filed evidence states:

> *I recommend that the Board deny Hydro's proposal to establish new supply cost variance accounts referred to as the "Isolated Systems Supply Cost Variance Deferral Account", the "Energy Supply Cost Variance Deferral Account" and the "Holyrood Conversion Rate Deferral Account". There is no justification for transferring these risks to consumers when Hydro has been assured a much higher, and uncontested, return on equity fixed by Government Directive OC2009-063.*

Hydro submits that Mr. D. Bowman's conclusion is inconsistent with (i) regulatory precedent in Canada for utilities with government directed ROE; (ii) regulatory precedent for utilities in Canada generally; and (iii) utilities in this province.

As noted previously, the BCUC in Decision G-96-04 granted approval of a deferral account, which transferred the risk and benefits of supply costs variances to customers. This approval was subsequent to Heritage Special Directive No. 2, which set BC Hydro's return on equity to the same levels as the most comparable investor-owned utility, grossed up for income tax.[266]

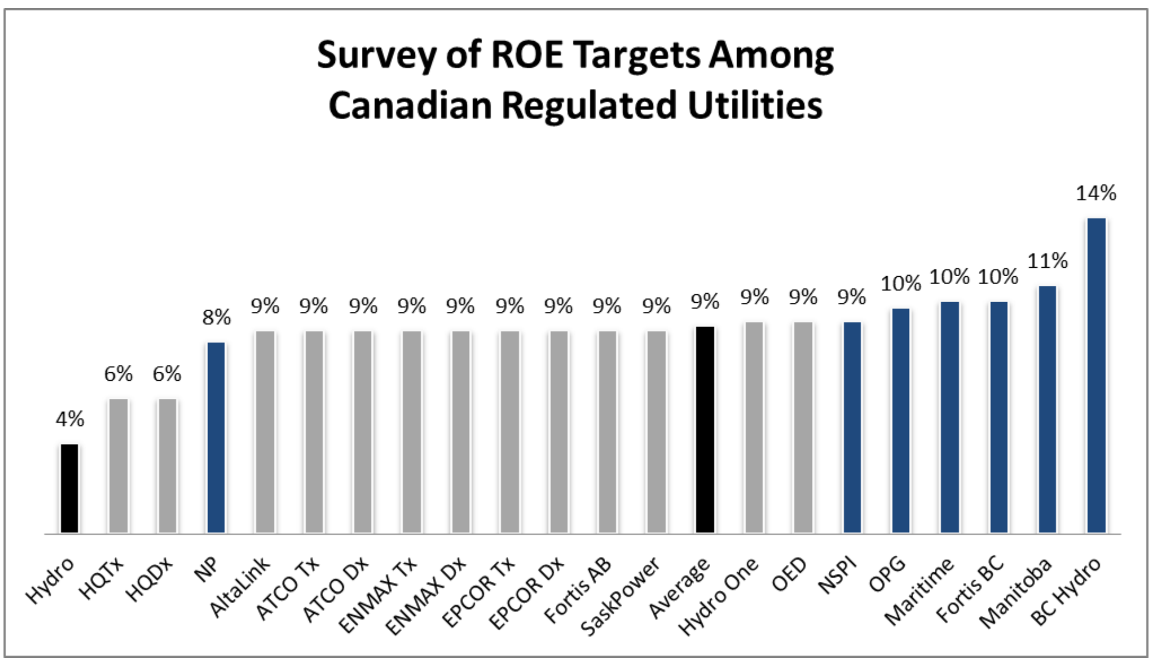
Hydro notes that OC2009-063 sets Hydro's return on equity to that of NP, the only investor-owned regulated utility in this jurisdiction. Hydro submits that Mr. D Bowman's statement that "there is no justification for transferring these risks to consumers when Hydro has been assured a much higher, and uncontested, return on equity fixed by Government Directive OC2009-

[266] Undertaking No. 167.

063"is not consistent with Canadian regulatory precedent for utilities with a government directed ROE.

Mr. D. Bowman's statement is also contradictory to utility practice in other jurisdictions across Canada. Mr. D. Bowman has only considered the change in Hydro's ROE from 2007. He has not considered whether these risks existed at the time that ROE was approved nor has he considered whether these deferrals are consistent with an ROE of 8.8% when compared to other utilities across Canada. Page 3.35 of Hydro's Amended Application provided a chart showing the ROE targets of other Canadian utilities. This chart is presented below, with utilities with approved supply deferrals per Hydro's response to PUB-NLH-388, noted in blue:

Chart 3



Hydro submits that based on utility practice across Canada, as presented in the above noted chart, supply deferrals are in fact quite common for Canadian utilities with a <u>higher</u> approved ROE than Hydro has proposed in this application. This is again inconsistent with Mr. Bowman's statement from page 16 of his pre-filed evidence:

> *There is no justification for transferring these risks to consumers when Hydro has been assured a higher, and uncontested, return on equity fixed by Government Directive OC2009-063. In fact, just the opposite is true - with a higher return on equity, Hydro should take on more risk.*

Finally, Hydro submits that Mr. Bowman's statements are not consistent with utility practice in this province. The Board has historically approved supply deferrals for both Hydro and NP, through the RSP and Rate Stabilization Account respectively. Hydro submits that regulatory precedent exists in this province for deferral of supply costs at the same level of return on equity as NP.

The evidence presented by Dr. Wilson with respect to Hydro's requested supply deferrals in relation to ROE, is largely similar to that of Mr. D. Bowman. Hydro disagrees with Dr. Wilson's testimony for the same reasons.

In the context of Hydro's Amended Application, Mr. D. Bowman's and Dr. Wilson's discussions on Hydro's incentive to manage supply costs are incomplete. Hydro has proposed a +/- $500,000 dead band on two of the three accounts. This represents a +/- $1,000,000 incentive, each fiscal year, for Hydro to limit the supply costs incurred. Hydro submits that this level of risk is sufficient incentive to manage these specific supply costs in a given year.

Section D.5: Management of the Rural Deficit

D.5.1 Amount of the Rural Deficit and Controllable Costs

- ***The Rural Deficit as a percentage of revenue requirement is stable.***

Hydro provides service to over 40 remote diesel communities.[267] It owns and operates 21 diesel-generating plants serving 4,600 customers on Isolated Systems. Hydro also directly

[267] November 23, 2015 Transcript, page 20.

serves 23,700 customers on the IIS. The Rural Deficit is the difference between the cost of providing service to these Rural Customers and the revenues collected from those customers.

The Rural Deficit has grown from $40.8 million in the 2007 Test Year to a forecast of $64.1 million in the 2015 Test Year. The growth in the amount of the Rural Deficit has resulted primarily from fuel costs, rather than from increases in costs that are controllable by Hydro. Controllable costs, which are primarily operating expenses, have remained relatively consistent from year to year, despite increasing wages and general inflationary pressure on material supply costs and other costs.[268] As illustrated in Chart 1 in Hydro's March 2015 Rural Deficit Annual Report, the Rural Deficit has been relatively consistent year over year when the impact of fuel costs (and the ROE established by Government directive) is removed.[269]

While the absolute dollar amount of the Rural Deficit has grown since 2007, it is important to put the total dollar amount into context. Evidence provided by NP makes it clear that the Rural Deficit allocated to NP was greater as a percentage of NP's total revenue requirement in 2002 than in either 2007 or 2015.[270] NP's allocation of the Rural Deficit as a percentage of its total revenue requirement declined from slightly more than 15.5% in 2002 to approximately 11.5% in 2007.[271] Under the proposed allocation methodology, NP's allocation of the Rural Deficit in 2015 falls in line with the 2007 percentage (i.e., approximately 11.8% of NP's total 2015 revenue requirement).[272]

[268] Amended Application, Regulated Activities Evidence, pages 2.82-2.83.
[269] Information Exhibit #8, page 3 and Chart 1.
[270] NLH-NP-019. See also October 7, 2015 Transcript, pages 129-130.
[271] In the response to NLH-NP-019, NP provided a bar chart showing the Rural Deficit allocated to NP as a percentage compared to NP's "remaining revenue requirement" and it also provided the dollar amounts for NP's total revenue requirement, including the Rural Deficit for 2002, 2007 and 2015. The actual percentages (NP's allocation of the Rural Deficit as a percentage of NP's total revenue requirement) for 2002 and 2007, and for 2015 under Hydro's proposed methodology, can be calculated using the information provided in the Pre-filed Evidence and Exhibit of Mr. Brockman, pages 8-9 together with the dollar amounts in NLH-NP-019.
[272] October 7, 2015 Transcript, page 130.

D.5.2 Customer Awareness and the Rural Deficit

- ***The Board should proceed cautiously in considering the addition of a line item on customer bills demonstrating the impact of the Rural Deficit.***

Dr. Feehan proposed that the amounts customers contribute to the Rural Deficit should be expressed on their bills because this would contribute to good public policy and, more specifically, inform any future public policy debate about the continuation of the Rural Deficit policy.[273] In response to a question from Board Hearing Counsel, Dr. Feehan also said that he saw no reason why the people receiving the subsidy should not see that on their bills just like the people who are paying the subsidy.[274]

The proposal that customers be made aware of who is contributing to the Rural Deficit and who is paying the cost of it gives rise to a number of implications that should be taken into account before any decision is made to adopt Dr. Feehan's suggestion. A decision to communicate information about which customers pay for the Rural Deficit and which customers benefit from it could result in an approach to customer communications that is selective, unpopular, and, potentially, provocative and even misleading. As noted by Mr. Fagan for Hydro in his testimony, research with focus groups would be advisable to ensure no unforeseen consequences of this action.[275]

It is also important to note that the proposed communication of information would be selective because it would specifically address the cross-subsidization effect of the Rural Deficit even though some element of cross-subsidization is, quite apart from the Rural Deficit, inherent in rates.[276] Of course, it is unavoidable that there will be cross-subsidization in customer rates, because it is not practicable to attempt to isolate the precise costs of serving each individual customer. Most people know that there are economic differences in the cost to serve different

[273] October 5, 2015 Transcript, page 13.
[274] October 5, 2015 Transcript, pages 71-72.
[275] October 6, 2015 Transcript, page 49.
[276] October 6, 2015 Transcript, pages 44-45.

customers.[277] Presumably, under Dr. Feehan's proposal, NP customers would be told that they are paying a share of the Rural Deficit. However, if one were to do a cost of service study of NP's more rural regions, one would come up with a fairly large rural subsidy being received (not paid) by rural customers on NP's own system.[278] Identifying Rural Customers on the IIS as a subsidized group is not much different than breaking NP's cost of service study into regions and coming up with an NP rural deficit that represents cross-subsidization of NP's rural customers.[279]

When a proposal was put forward that a rural surcharge be introduced on the bills of NP in 1996, the proposition was opposed by all intervenors, it was a topic that received considerable attention in the media and was unpopular with customers.[280] The proposed communication would potentially be provocative as well. According to Mr. Fagan's testimony, his experience from the 1995 Rural Rate Inquiry indicated that customers in some of Hydro's rural areas are offended by the notion that, although their resources have been used to support the rest of the Province, there is perceived to be a need to highlight that their electricity rates are subsidized.[281]

The proposed communication would also potentially be confusing to customers because NP's customer would be told that they are paying the Rural Deficit when in fact it is likely that it costs more to serve customers in some of NP's rural areas than it does to serve customers in some of Hydro's rural interconnected areas.[282] Further, such communication has the potential to pit neighbouring communities against one another: those that are being "subsidized" (e.g., Baie Verte) and those who are "subsidizing" providing of services to isolated customers (e.g., Deer Lake).[283]

[277] October 6, 2015 Transcript, page 40.
[278] October 6, 2015 Transcript, page 37.
[279] October 6, 2015 Transcript, pages 47-48.
[280] October 6, 2015 Transcript, page 39.
[281] October 6, 2015 Transcript, pages 38-39.
[282] October 6, 2015 Transcript, pages 44-45.
[283] October 6, 2015 Transcript, pages 36-37.

It is perhaps easy to jump to a conclusion that there can be no harm in providing more information to customers about the Rural Deficit. As noted above, Hydro respectfully submits that Dr. Feehan's proposal has a number of implications that should be carefully considered before any decision is made to adopt that proposal. Further, if the Board decides that information should be communicated about the customers who pay the Rural Deficit and the customers who benefit from it, Hydro submits that consideration should be given to framing a message that conveys a perception of fairness to all parties.[284]

D.5.3 Conservation Measures to Control the Rural Deficit

- ***Hydro has continued its efforts to reduce the Rural Deficit by promoting energy efficiency in isolated communities.***

Hydro's Rural Deficit Annual Report of March 2015 summarizes many initiatives taken by Hydro to control the overall amount of the Rural Deficit.[285] These include a number of internal energy efficiency initiatives that were completed or launched by Hydro in 2014, as well as ongoing cost control measures that have been continued by Hydro. This Report also describes CDM program initiatives and capital initiatives pursued by Hydro to control the Rural Deficit.

Hydro's work on energy efficiency initiatives in isolated communities goes back as far as the early 1990s.[286] When implementation of Hydro's takeCHARGE partnership with NP began in 2009, the joint effort did not include programs targeted specifically at isolated communities, but the takeCHARGE programs were open to customers in isolated communities who were eligible for them.[287]

Hydro partnered with the Government on a pilot project in isolated communities in 2010 to 2011 and then followed up by launching two programs specifically targeted at these

[284] October 6, 2015 Transcript, pages 37-38 and 49. Hydro also suggested neutral wording, such as rate equalization policy adjustment, rather than using a work like "subsidy". See October 6, 2015 Transcript, page 37.
[285] Information #8.
[286] November 24, 2015 Transcript, page 3.
[287] November 24, 2015 Transcript, pages 2-4.

communities in 2012. The two initiatives are: (i) the Isolated Systems Community Energy Efficiency Program and (ii) the Isolated Systems Business Efficiency Program. Hydro delivers programs in isolated communities under the takeCHARGE brand, independently of its joint effort with NP.[288]

The Isolated Systems Community Energy Efficiency Program includes a number of features such as the provision of kits of small energy efficiency technologies to homes and businesses, coupons for discounts on a number of energy efficiency products, increased incentives for home insulation retrofits and work to assess the opportunity for, and challenges of, larger-scale home retrofits.

The Isolated Systems Community Energy Efficiency Program is a three-year program that is expected to result in total energy saving of 3.3 GWh/year and fuel cost savings of $1.1 million per year.[289] Under this program, both residential and commercial customers are provided with energy efficiency support and assistance that covers a wide range, including direct install of efficiency products, education and awareness, coupons and incentives.[290]

From 2012 to 2014, Hydro was able to reach 83% of its customers in isolated communities under the Isolated Systems Community Energy Efficiency Program.[291] At this point, Hydro has not embarked on a "whole home approach" to CDM in these communities because changes to a building envelope such as addition of insulation contribute to existing issues of water infiltration, mold and condensation and because of concerns that major home renovations are not within the purview of an electrical utility.[292]

The Isolated Systems Business Efficiency Program provides technical support and incentives to commercial customers. Extensive time and effort are required to bring commercial customers

[288] PUB-NLH-313.
[289] NP-NLH-098 (Revision 1, Dec 9-14), Attachment 2, page 8 of 10.
[290] PUB-NLH-313.
[291] November 23, 2015 Transcript, page 20.
[292] November 24, 2015 Transcript, pages 5-7 and 171-172.

through the process:[293] customers are given a free walk-through audit of a facility followed by a report on energy saving opportunities.[294] This is also a three-year program and an evaluation is planned after the third year of the program.[295]

The Isolated Systems Business Efficiency Program is expected to result in total energy savings of 180 MWh. By the end of 2012, more than 40 audits had been completed with recommendation reports provided to customers.[296] To date, 58 commercial customers have been visited under the Isolated Systems Business Efficiency Program.[297]

As part of its CDM efforts in isolated communities, Hydro also carries out energy efficiency improvements at its own facilities. Hydro's CDM team consults with and assists the Hydro Operations group in making Hydro's own operations in isolated communities more efficient.[298]

The estimated 2015 impact of Hydro's CDM initiatives on the Rural Deficit has been presented in evidence.[299] For the 2015 Test Year, savings from customer-focused energy efficiency measures (including 2013 actuals) are estimated to be 9.4 GWh, or, as a dollar amount, more than $1 million. For the 2015 Test Year, savings from internally focused energy efficiency measures (including 2013 actuals) are estimated to be 4.2 GWh, or more than $600,000. Hydro submits that its CDM activities have produced a successful outcome that contributes significantly to its efforts to constrain the amount of the Rural Deficit.

D.5.4 Cost Control Measures to Control the Rural Deficit

- ***Hydro has undertaken numerous initiatives resulting in cost savings or avoided cost in Rural Deficit areas.***

[293] PUB-NLH-313.
[294] NP-NLH-098 (Revision 1, Dec 9-14), Attachment 2, page 9 of 10.
[295] *Ibid*.
[296] NP-NLH-098 (Revision 1, Dec 9-14), Attachment 2, page 9 of 10.
[297] November 23, 2015 Transcript, page 21.
[298] November 24, 2015 Transcript, page 175.
[299] NP-NLH-098 (Revision 1, Dec 9-14), Attachment 1, page 1 of 1.

Hydro has implemented many cost reduction initiatives to contain the growth of the Rural Deficit. In particular, given its mandate to provide least-cost, safe and reliable power to all its customers, Hydro strives to manage the costs of serving Rural Customers with a view to providing reliable service while minimizing the amount of the Rural Deficit.[300] Actions taken by Hydro that contain the growth of the Rural Deficit are explained in evidence prepared specifically for the purposes of this proceeding[301] and in the Rural Deficit Annual Reports, also on the record of this proceeding, that Hydro files each year with the Board.[302]

Hydro has undertaken both dedicated efforts aimed at controlling the Rural Deficit and Hydro-wide projects that result in cost savings or avoided costs in Rural Deficit areas.[303] In addition to the CDM program initiatives that are discussed above, efforts to control operating costs include internal energy efficiency initiatives and ongoing cost control measures.[304] Hydro has also implemented capital-spending initiatives that contribute to its effort to control the Rural Deficit.[305]

Examples of the numerous initiatives and programs undertaken by Hydro that result in cost savings or avoided costs in Rural Deficit areas include the following:

- Capturing waste heat;
- Monitoring diesel system fuel efficiency;
- Utilizing commercial flights where practical, rather than more expensive helicopter use;
- Using a fuel-efficient mix of engines to supply load;
- Enhancing the effectiveness of planning and scheduling to minimize outages and delays;
- Carrying out life cycle cost analysis for diesel engines;
- Implementing automatic meter reading;
- Installing in-line heaters at diesel plants; and

[300] Amended Application Regulated Activities Evidence, page 2.83.
[301] NP-NLH-098 (Revision 1, Dec 9-14), Attachment 1.
[302] NP-NLH-099 (Revision 2, Dec 9-14), Attachment 1; NP-NLH-098 (Revision 1, Dec 9-14), Attachment 2; and Information Exhibit #8.
[303] NP-NLH-098 (Revision 1, Dec 9-14).
[304] Information Exhibit #8, pages 3-5.
[305] *Ibid.*, page 8.

- Implementing e-billing and in-house printing of customer bills.[306]

In the case of many of Hydro's projects and initiatives, the reduction in the Rural Deficit by way of costs saved or avoided is not quantifiable.[307] Even so, the estimated 2015 Test Year total savings (resulting from only those reductions that are quantifiable) exceed $2 million.[308]

Section D.6: Other Issues

D.6.1 Customer Service Strategy

The Parties agreed Hydro's "Customer Service Strategic Roadmap 2015-2017" reflects appropriate customer service improvement objectives. The parties stipulated their agreement did not preclude additional customer service improvements being raised during the hearing of this Application or being considered by the Board.[309]

D.6.2 Issues Raised By the Nunatsiavut Government

On November 30, 2015, the Board heard testimony from two witnesses appearing on behalf of the Nunatsiavut Government: Darryl Shiwak, Nunatsiavut's Minister of Lands and Natural Resources; and Chris Henderson of Lumos Energy, Nunatsiavut's clean energy advisor,[310] who was offered as Nunatsiavut's expert on sustainable energy development in northern climates.[311] Minister Shiwak testified about socioeconomic conditions in Nunatsiavut's communities, particularly as regards energy affordability.[312] Minister Shiwak also discussed Nunatsiavut's current and future energy needs, the ongoing need for improvements to the diesel-generated electricity systems serving Nunatsiavut's communities, the impact of higher rates and his views on Muskrat Falls.[313] On cross-examination,[314] Minister Shiwak characterized

[306] Amended Application Regulated Activities Evidence, page 2.83.
[307] NP-NLH-098 (Revision 1, Dec 9-14).
[308] Total of amounts shown at NP-NLH-098 (Revision 1, Dec 9-14), Attachment 1.
[309] Settlement Agreement, page 4, paragraph 21.
[310] November 30, 2015 Transcript, pages 35, line 25 to 36, line 1.
[311] November 30, 2015 Transcript, page 34, lines 1-13.
[312] November 30, 2015 Transcript, pages 6, line 16 to 14, line 10.
[313] November 30, 2015 Transcript, pages 14, line 11 to 23, line 8.

the takeCHARGE program as "a good program, but more needs to be done to get into the communities".[315]

Mr. C. Henderson's testimony previewed a report he began two years ago to assess Nunatsiavut's energy needs and resources, and to identify opportunities to reduce energy consumption and energy costs. Mr. C. Henderson advised that his report has generated a Nunatsiavut energy security plan, which will be made available to the Government, the Board, and interested stakeholders shortly.[316] Drawing on experience with other First Nations communities in northern climates, Mr. C. Henderson advocated a "more holistic energy community energy planning approach and a more holistic home energy efficiency and conservation approach,"[317] which Mr. C. Henderson developed in consultation with Hydro and the Board.[318] Mr. C. Henderson identified innovation opportunities for Hydro's diesel generation facilities,[319] and he elaborated on these opportunities during cross-examination.[320] Hydro believes the Board must give consideration to its regulatory framework when considering the Nunatsiavut Government's submissions.[321] Hydro appreciates the intervention of the Nunatsiavut Government and Minister Shiwak, and Mr. C. Henderson for the depth and evenhandedness of their testimony.

E. RATE IMPLEMENTATION

E.1 COMPLIANCE FILING

Subsequent to the final Order for the GRA, Hydro will make a compliance filing reflecting the Board's decisions. The compliance filing will finalize the revenue deficiency calculations for 2014 and 2015 and provide recovery proposals by customer class. COS studies for each year will be provided to determine the revenue deficiency by customer class.

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[314] November 30, 2015 Transcript, pages 23, line 24 to 28, line 2.
[315] November 30, 2015 Transcript, page 27, lines 1 to 2.
[316] November 30, 2015 Transcript, pages 35, line 18 to 36, line 25.
[317] November 30, 2015 Transcript, pages 41, line 23 to 42, line 1.
[318] November 30, 2015 Transcript, page 37, lines 3 to 6.
[319] November 30, 2015 Transcript, pages 44, line 11 to 45, line 25.
[320] November 30, 2015 Transcript, pages 57, line 11 to 67, line 16.
[321] Order No. P.U. 8(2007), Appendix A.

Delayed implementation of customer rates in 2016 will also contribute to a further revenue deficiency attributable to certain customer classes. The compliance application will provide a forecast 2016 revenue deficiency by customer class based on the 2015 Test Year sales forecast and include a proposal for appropriate recovery.

The compliance application will include proposals that reflect the Board's determinations in the final GRA Order for the finalization of the 2015 Test Year revenue requirement and 2015 Test Year rate base for use in the establishment of customer rates in 2016. This filing will include a 2015 Test Year COS Study reflecting the approved revenue requirements for use in establishing customer rates.

The final GRA Order will also permit Hydro to update the RSP balances for 2015 reflecting the updated 2015 Test Year inputs for fuel cost, hydrology, load, and customer rates. The RSP balances currently being reported on an interim basis reflect the 2007 Test Year inputs.

E.2 RECOVERY OF REVENUE DEFICIENCIES

The rates proposed in the GRA evidence do not reflect the recovery of the revenue deficiencies already incurred as the proposed rates are based upon recovery of 2015 Test Year costs. Subject to the Board's finalization of the amounts to be recovered, Hydro's compliance application will present proposals for recovery of the:

(i) 2014 Revenue Deficiency of $45.9 million as approved for deferral in Order No. P.U. 58(2014) with recovery being subject to the Board's subsequent determination;

(ii) 2015 Net Income Deficiency of $60.5 million per Hydro's Amended Cost Deferral Application, dated November 12, 2015, with recovery being subject to the Board's subsequent determination; and

(iii) Forecast 2016 revenue deficiency resulting from delayed implementation of customer rates beyond January 1, 2016.

One method to deal with the recovery of the revenue deficiencies to be approved by the Board is to recover the deficiency through higher rates to be paid by customers in the future (i.e., as a rate rider or cost recovery amortization).[322] Another method for consideration is to use the material fuel savings that have accumulated and are reflected as credit balances in the RSP. In the Amended Application, Hydro proposed the recovery of the 2014 deficiency through the use of the credit balances in the RSP.[323] Hydro believes using the RSP credit balances to recover revenue deficiencies is consistent with intergenerational equity in that it applies funds already recovered from customers to recover costs that have already been incurred to provide service to those customers.[324]

Mr. D. Bowman agreed that the methodology for disposing of RSP balances should be reviewed in light of the limited remaining operating time of the Holyrood thermal plant.[325] Mr. D. Bowman also recommended the use of the RSP credit balances to reduce the volatility of customer rates over the period to 2017.[326]

Mr. Brockman agreed with the use of RSP credit balances to avoid increasing future rates for costs already incurred. [327] Mr. Dean also agreed; he stated:

> *A recovery method that uses an existing balance is recommended over methods such as a rate rider that would affect future years. A rate rider would worsen the rate impact that the Industrial Customers are experiencing and would cause intergenerational inequity due to the changing dynamics within the Industrial Customer class.*[328]

[322] This is similar to the method approved by the Board in the case of NP in its 2013-2014 General Rate Application. In Order No. P.U. 13(2013), the Board approved the amortization of the forecast 2013 revenue shortfall over three years, commencing in 2013.
[323] At year-end 2014, there was a $35 million credit balance in the RSP load variation component and a $43 million credit in the RSP hydraulic component.
[324] October 5, 2015, Transcript, page 107, lines 10 – 25.
[325] Pre-filed evidence of C. Douglas Bowman dated June 1, 2015, page 14, lines 22 – 24.
[326] Pre-filed evidence of C. Douglas Bowman dated June 1, 2015, page 15, lines 19 – 22.
[327] September 28, 2015 Transcript, page 121, lines 1-20.
[328] Pre-filed evidence of Mr. Dean, dated June 4, 2015, pages 19, line 28 to 20, line 3.

As indicated earlier, the final GRA Order will permit Hydro to update the RSP balances for 2015. Hydro submits it is appropriate to utilize the 2015 year-end credit balances in the RSP load variation component and the hydraulic variations component, where appropriate, to limit the amount of revenue deficiency that will be recovered through rates from customers. Any portion of the revenue deficiencies not approved for recovery through the RSP should be proposed for recovery through future customer rates. This approach will likely be required for recovery of revenue deficiency attributable to customers on the Labrador Interconnected System.

F. CONCLUSION/ORDER REQUESTED

In conclusion, Hydro under the *Act*, and specifically under Sections 58, 64, 70, 71, 75, 76, 78 and 80, proposes the following, effective January 1, 2016. The following is divided into two sections: settled and non-settled matters.

F.1 SETTLED ISSUES

There were two settlement agreements filed with the Board in this matter. In that connection, Hydro seeks the Board's approval of those agreements, and more particularly, proposes that:

(1) The allowable range of return on rate base of +/- 20 basis points be approved;[329]

(2) Hydro's treatment to include actuarial gains and losses on Employee Future Benefits of $1.6 million in the 2015 Test Year as part of Hydro's revenue requirement be approved;[330]

(3) Hydro's Asset Retirement Obligations include depreciation and accretion expenses of $2.6 million and $2.6 million, respectively for the 2014 and 2015 Test Years be approved;[331]

[329] Item 7 of the Settlement Agreement.
[330] Item 8 of the Settlement Agreement.
[331] Item 9 of the Settlement Agreement.

(4) The total generation credit for NP be increased to 119,329 kW;[332]

(5) Hydro's proposal to defer and amortize annual customer energy conservation program costs, commencing in 2015, over a discrete seven year period in a CDM Cost Deferral Account, be approved;[333]

(6) The costs related to the Application be recovered in customer rates evenly over a three year period, commencing with the date that new rates approved in this proceeding become effective with the amount of such costs to be determined by the Board;[334]

(7) The Service Agreement between Hydro and CBPP, which was approved on a pilot basis by the Board in Order No. P.U. 4(2012), be approved to continue on a pilot basis;[335]

(8) An industrial wheeling rate calculated in accordance with the methodology proposed by Hydro in its Application be approved;[336]

(9) Hydro report functionally oriented key performance indicators as required by the Board in Order No. P.U. 14(2014) based on the most recent Test Year COS Study approved by the Board rather than on a forecast basis;[337]

(10) In preparation for the implementation of customer rates reflecting the costs of the Labrador-Island interconnection, Hydro will file with the Board the following:[338]

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[332] Item 14(a) of the Settlement Agreement.
[333] Item 17 of the Settlement Agreement.
[334] Item 18 of the Settlement Agreement.
[335] Item 19 of the Settlement Agreement.
[336] Item 20 of the Settlement Agreement.
[337] Item 22 of the Settlement Agreement.
[338] Item 23 of the Settlement Agreement.

i. a marginal cost study no later than December 31, 2015;
ii. a cost of service methodology report no later than March 31, 2016; and
iii. a report on the Rate Stabilization Plan and supply cost recovery mechanisms no later than June 15, 2016;

(11) A generic cost of service hearing be held following the filing of the reports outlined in (10) above;

(12) Hydro file a GRA on or before March 30, 2017 proposing rates based on a 2018 Test Year;[339]

(13) the cost of service methodologies in Exhibit 13(2015 Test Year COS) be approved with respect to:

i. the treatment of the curtailable load of Newfoundland Power;
ii. the classification of wind energy purchases as 100% energy related;
iii. the classification of all Holyrood fuel costs to energy;
iv. the use of the load forecast provided by NP; and
v. the specific assignment of the frequency converter to CBPP Limited; [340]

(14) The calculation of the capacity factor for the Holyrood Generating Plant be based on a historical five-year period from 2010 to 2014, inclusive;[341]

(15) The demand charge to NP will equal $4.75 per kW of billing demand;[342]

(16) The end block energy rate to NP will be determined based on the 2015 Test Year No. 6 fuel price divided by the 2015 Test Year Holyrood fuel conversion Factor, both as are determined by the Board;[343]

[339] Item 23(d) of the Settlement Agreement.
[340] Item 7 of the Supplemental Settlement Agreement.
[341] Item 8 of the Supplemental Settlement Agreement.
[342] Item 10(i) of the Supplemental Settlement Agreement.
[343] Item 10(ii) of the Supplemental Settlement Agreement.

(17) The approved 2015 Test Year revenue requirement that is not recovered through the NP demand and end-block energy charge will be used to compute the first block energy charge;[344]

(18) The wholesale rate charged to NP will include a curtailable load credit as proposed in the Amended Application;[345]

(19) Hydro's proposed CDM Recovery Adjustment be approved so as to provide for recovery of costs charged annually to the CDM Cost Deferral Account;[346]

(20) Costs associated with Hydro's capacity assistance agreements with Vale and Corner Brook Pulp and Paper Limited be treated as demand related in the 2015 Test Year COS Study;[347]

(21) If the load variation component is maintained as an element of the RSP, the allocation of year-to-date net load variations for NP and industrial customers among the customer groups be based upon energy ratios, with effect from the date to be determined by the Board (there is no settlement on the effective date—Hydro proposes that the effective date be September 1, 2013);

F.2 HYDRO'S PROPOSALS ON ISSUES NOT SETTLED

On the matters that were not settled by the parties and therefore did not constitute elements of either of the settlement agreements, in summary Hydro proposals are as follows.

F.2.1 Revenue Requirement

(1) Hydro's 2014 Test Year Revenue Requirement of $560,755,000 be approved;[348]

[344] Item 10 of the Supplemental Settlement Agreement.
[345] Item 11 of the Supplemental Settlement Agreement.
[346] Item 12 of the Supplemental Settlement Agreement.
[347] Item 14(b) of the Settlement Agreement.

(2) Hydro's adjusted 2015 Test Year Revenue Requirement of $579,577,352 be approved for the purpose of determining 2015 Revenue Deficiency;[349]

(3) Hydro's 2015 Test Year Revenue Requirement of $584,677,352 be approved for the purpose of setting customer rates;[350]

(4) Hydro's forecast capital structure for the 2014 Test Year be approved with a weighted average cost of capital of 7.32%;

(5) Hydro's forecast capital structure for the 2015 Test Year be approved with a weighted average cost of capital of 6.82%;

(6) Pursuant to Order in Council OC2009-063, for purpose of calculating Hydro's return on rate base, the return on equity last approved by Order No. P.U. 13 (2013), as a result of NP's general rate application, of 8.80% be approved for the 2014 Test Year and the 2015 Test Year;

(7) Hydro be allowed a rate of return on forecast average rate base for the 2014 Test Year of 7.12%;

(8) Hydro be allowed a rate of return on forecast average rate base for the 2015 Test Year of 6.82%;

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[348] Equals the $560,855,000 proposed 2014 Test Year Revenue Requirement in the Amended Application less $2,100,000 (i.e. the impact on 2014 Test Year Revenue Requirement resulting from adjustments to reflect delayed in-service dates of 2014 capital projects until 2015). See PUB-NLH-487.

[349] Equals the $662,475,000 proposed 2015 Test Year Revenue Requirement in the Amended Application less (i) $75,878,230 No. 6 fuel cost savings based on a Test Year No. 6 fuel cost of $64.41 per barrel (ii) less $5,100,000 (i.e. the impact on 2015 Test Year Revenue Requirement resulting from adjustments to reflect delayed in-service dates of 2014 capital projects in the 2015 rate base opening balance); (iii) less $1,919,418 Isolated supply costs savings referenced in the October 28, 2015 correspondence with the Board on projected 2016 fuel costs. See PUB-NLH-487.

[350] Equals the $662,475,000 proposed 2015 Test Year Revenue Requirement in the Amended Application less (i) $75,878,230 No. 6 fuel cost savings based on a Test Year No. 6 fuel cost of $64.41 per barrel; and (ii) less $1,919,418 Isolated supply costs savings referenced in the October 28, 2015 correspondence with the Board on projected 2016 fuel costs.

(9) The 2015 Test Year costs related to capacity assistance agreements be approved for inclusion in 2015 Test Year Revenue Requirement.

F.2.2 Deferral and Recovery Mechanisms

(10) The proposed Isolated Systems Supply Cost Variance Deferral Account be approved effective January 1, 2015;

(11) The proposed Energy Supply Cost Variance Deferral Account be approved effective January 1, 2015;

(12) The proposed Holyrood Conversion Rate Account be approved effective January 1, 2015.[351]

F.2.3 Amortizations

(13) An estimated $1.2 million (the final amount to be set after the conclusion of the hearing) in external regulatory costs be deferred and recovered over three years in accordance with the Settlement Agreement;[352]

(14) The regulatory treatment of Capacity Related Supply Cost Variances, whereby it would be amortized over a five-year period commencing in the 2015 Test Year, as proposed in Hydro's application filed October 8, 2014, be approved.[353]

F.2.4 Rate Base

(15) Hydro's average rate base for 2013 of $1,548,371 be approved.[354]

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[351] This account was requested, explained and described in Supplemental evidence filed by Hydro on January 14, 2015.
[352] Originally requested on page 3.22 of Hydro's Amended Application, updated to $1.2 million per line 35 of Undertaking 55.
[353] Pending a determination of this matter in the Prudence Review process
[354] Finance Evidence, Schedule I, page 5 of 11, line 21.

(16) Hydro's forecast average rate base for the 2014 Test Year of $1,618,867 be approved for determining 2014 revenue deficiency;[355]

(17) Hydro's forecast average rate base for the adjusted 2015 Test Year of $1,728,324 be approved for the purpose of approving 2015 revenue deficiency;[356]

(18) Hydro's forecast average rate base for the 2015 Test Year of $1,802,024 be approved for the purpose of approving rates;[357]

F.2.5 Rate Stabilization Plan

(19) Hydro will propose a plan for the finalization of the phase-in of IC rates to be filed with its compliance application;

(20) As there is no further Rural Labrador Interconnected Automatic Rate Adjustment, Section 1.3(b) be removed from the RSP Rules;

(21) The Section E – Historical Plan Balance be removed;

(22) The load variation component be maintained as an element of the RSP;

(23) The allocation of year-to-date net load variations for NP and industrial customers among the customer groups be based upon energy ratios, with effect from September 1, 2013;

[355] Equals the $1,692,567,000 proposed 2014 Test Year rate base in the Amended Application less $73,700,000 (i.e. the impact on 2014 Test Year Rate Base resulting from adjustments to reflect delayed in-service dates of 2014 capital projects until 2015).
[356] Equals the $1,802,024,000 proposed 2015 Test Year rate base in the Amended Application less $73,700,000 (i.e. the impact on 2015 Test Year Rate Base resulting from adjustments to reflect delayed in-service dates of 2014 capital projects until 2015).
[357] Equals the $1,802,024 proposed 2015 Test Year rate base in the Amended Application.

F.2.6 Revenue Deficiency

(24) The RSP credit balance be used, where appropriate to offset the revenue deficiency that occurred due to delays in implementation of rate changes beyond January 1. 2014;

(25) The portion of the revenue deficiency not recovered using the RSP credit balance be deferred for future recovery through a rate rider or through a cost recovery amortization included in revenue requirement for determining rates.

F.2.7 General Rate and Cost of Service Matters

(26) The Labrador Transmission demand-related rate be set at $1.25/kw/month;

(27) Commencing January 1, 2014 the Rural Deficit be allocated based on revenue requirement;

(28) Hydro use the indexed cost of assets in allocation of O&M costs to specifically assigned assets in the cost of service study for the 2014 and 2015 Test Years;

(29) The Board approve the 2015 load forecast for IIC for use in the 2015 Test Year COS Study;

(30) The average system losses used in the calculation of the energy charge to Industrial Customers for non-firm service be increased to 3.47%;

(31) The Board approve the proposed above average increases in customer rates for Hydro Rural non-Government Domestic and General Service customers on Isolated systems; and

(32) Upon hearing this Amended Application, the Board grant such alternative, additional or further relief as the Board shall consider fit and proper in the circumstances.

ALL OF WHICH IS RESPECTFULLY SUBMITTED.

newfoundland labrador
hydro
a nalcor energy company

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February 5, 2016

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

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

Dear Ms. Blundon:

Re: Application by Newfoundland and Labrador Hydro for a 2016 Standby Fuel Deferral Account for Fuel Consumed in Combustion Turbines and Diesel Generators

Hydro is applying for a deferral account to provide for the recovery of unforeseen costs it is incurring with respect to fuel for its standby combustion turbine and diesel generators.

Since July of 2015, precipitation and inflows in hydro-electric reservoirs on the Island have been very low. In addition, the current snow pack is well below normal. Meanwhile, Hydro continues to see strong load growth and has been experiencing outages and deratings of its Holyrood Thermal Generating Station ("Holyrood TGS"). Based on these circumstances, if action is not taken, there is a very real risk that the reservoirs will remain far below normal, putting Hydro's ability to provide sufficient energy generation to its customers in jeopardy.

The requirement to consume diesel fuel for these purposes is caused primarily by the low hydrology, not just in Hydro's reservoirs but also in the reservoirs not owned by Hydro, including the Exploits resources. In addition, Newfoundland Power and Corner Brook Pulp and Paper Limited have informed Hydro that their inflows have been, and are expected to be, lower than usual. Due to these circumstances and the need to provide reliable service to its customers, Hydro will be running combustion turbines and diesel generators at much higher levels in 2016 than in previous years.

The amount of energy that will be generated from standby resources will be far greater than the amount forecast in the 2015 Test Year for the General Rate Application and the financial impact of this could be material. Hydro is therefore applying for a deferral account to manage this generation requirement. Please find enclosed the original and twelve copies of Hydro's application, supporting affidavit, draft order and a report supporting the application.

Should you have any questions, please contact the undersigned.

Yours truly,

NEWFOUNDLAND AND LABRADOR HYDRO

Geoffrey P. Young
Senior Legal Counsel

GPY/bs

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

IN THE MATTER OF the *Electrical Power Control Act,* R.S.N.L. 1994, Chapter E-5.1 (the *EPCA*) and the *Public Utilities Act*, R.S.N.L. 1990, Chapter P-47 (the *Act*), and regulations thereunder;

AND IN THE MATTER OF an Application by Newfoundland and Labrador Hydro (Hydro) pursuant to section 70 of the *Act,* for approval of a deferral account for diesel fuel consumed in 2016 to provide capacity and energy to the Island Interconnected System

TO: The Board of Commissioners of Public Utilities (the Board)

THE APPLICATION OF NEWFOUNDLAND AND LABRADOR HYDRO (Hydro) STATES THAT:

1. Hydro is a corporation continued and existing under the *Hydro Corporation Act, 2007*, is a public utility within the meaning of the Act and is subject to the provisions of the *Electrical Power Control Act, 1994.*

2. Hydro is the primary generator of electricity in Newfoundland and Labrador. Hydro meets the total generation needs of the Island Interconnected System through a combination of hydraulic and thermal resources. To ensure that Hydro has sufficient water in the reservoirs to meet its needs, during times of low reservoir inflows, Hydro must rely to a greater extent on thermal generating resources. Hydro cannot allow its reservoirs to fall below a safe threshold; in order to be certain of its ability to meet its energy generation needs, it must run sufficient thermal generation to assure that it can do so in the lowest foreseeable hydrologic conditions.

3. Normally, Hydro is able to meet its thermal generation needs in low precipitation years by increasing its generation at the Holyrood Thermal Generating Station ("Holyrood TGS"). Hydro's combustion turbines and diesel generators are typically used as standby

generation for peaking and capacity. In addition, Hydro purchases standby energy from Newfoundland Power by paying the associated fuel costs. Due to experiencing particularly low precipitation in the second half of 2015 and the first month of 2016, Hydro determined that it needs to generate a greater proportion on its energy from its thermal resources.

4. In late 2015 and to date in 2016, Hydro experienced low precipitation, low inflows and lower than usual snowpack in its reservoirs and in the reservoirs and in all hydro-electric reservoirs on the Island. Hydro understands that similarly low hydrologic conditions are occurring in the reservoirs of Hydro's customers with hydraulic generation. Also, Hydro is experiencing reduced energy generation at the Holyrood TGS in recent months due to reheater tube failures in Unit 2 requiring repairs and a likelihood of similar problems occurring in Unit 1, requiring an operational derating of these units. In addition, Hydro has been experiencing a period of continuous customer load growth. This combination of factors has resulted in Hydro needing to run standby thermal generating sources, notably combustion turbines and diesel generators, at considerably higher levels than forecast.

5. Aside from the Holyrood TGS, the other standby thermal generating resources available to Hydro, consume diesel fuel. At present, while Hydro's consumption of No. 6 fuel for its Holyrood TGS is stabilized through the Rate Stabilization Plan such that the actual cost of this fuel consumed is recovered from customers through rate adjustments, no such account or mechanism exists for the consumption of diesel fuel (No. 2 fuel). Hydro did apply for an Energy Supply Cost Variance Account ("ESCVA") in its Amended 2013 General Rate Application (GRA), a component of which addressed diesel costs incurred on the Island Interconnected System, but no order has issued as to that application to date and one is not expected immediately.

6. In order to provide reliable service to its customers and to assure a secure supply of energy throughout late 2015 and in 2016, Hydro has had no choice but to consume much more diesel fuel than was expected in its other thermal standby generating resources. Depending upon Island hydrology and hydro-electric output (whether Hydro's resources or otherwise), and upon customer load and the output of the Holyrood TGS, the amount of diesel fuel consumed could be material, as high as 215 GWh whereas the GRA test year forecast was 11.3 GWh. At current fuel prices, this could result in an exposure to Hydro of $33.3 million.

7. Hydro therefore applies for a deferral account to provide for the deferral and recovery of diesel fuel costs incurred on the Island Interconnected System for standby generation. A description of the proposed deferral account, and the need for this account at this time, are more thoroughly and particularly described and explained in the attached Report.

8. The Applicant submits that the proposed deferral account is reasonable and will assist Hydro in ensuring that it continue to provide service which is reasonable safe and adequate and just and reasonable as required by Section 37 of the *Act*.

DATED at St. John's, in the Province of Newfoundland and Labrador, this 5th day of February 2016.

Geoffrey P. Young
Counsel for the Applicant
Newfoundland and Labrador Hydro
500 Columbus Drive P.O. Box 12400
St. John's, NL A1B 4K7
Telephone: (709) 737-1277
Facsimile: (709) 737-1782

2016 Standby Fuel Deferral Application

February 5, 2016

newfoundland labrador
hydro
a nalcor energy company

Table of Contents

1.0 Overview: Increased Standby Generation For Energy

Newfoundland and Labrador Hydro (Hydro) has a mandate to provide energy to meet customers' requirements. To provide that energy, Hydro employs a planning methodology which balances hydraulic and thermal production and this balance is adjusted annually depending on the available hydrology. Hydro has a strong focus on ensuring the economic dispatch of its generation and specifically focuses on maximizing generation from hydraulic sources while minimizing generation from thermal sources in order to manage costs to customers. In periods of low precipitation, Hydro relies more on its thermal generation fleet to meet shortfalls in hydraulic production.

Hydro's current position is that low precipitation levels in late 2015 and to date in 2016 have reduced storage levels. Therefore, an increase in thermal generation, more than is currently provided for in rates charged to customers, is required. Specifically;

- Hydro's reservoir storage is at 48% and is the lowest level since 1993. Recent inflows into Hydro's reservoirs are lower than those experienced in all years of the Critical Dry Sequence, which represents the three driest years on record: 1959, 1960, and 1961. Hydro plans its system to meet customer needs should the Critical Dry Sequence reoccur.
- At this time, for Hydro's reservoirs to recover from current levels, Hydro estimates it requires 28 major precipitation events over the next 20 weeks.
- As a result of the forth lowest inflows in 65 years, Hydro has proactively increased its level of thermal production.
- The additional expected thermal generation required to offset low hydrology for the remainder of 2016 is approximately 1,100 GWh.
    - The Holyrood component of the additional thermal generation due to low hydrology is estimated to be 900 GWh, bringing the 2016 total production at Holyrood to 2,500 GWh, which is more than 200% of its recent average annual output.
    - Standby Generation units are, therefore, required to produce the remaining amount, which is estimated to be in excess of 200 GWh[1], compared to 11 GWh in the 2015 Test Year.

[1] In a 1961 inflow scenario, Hydro is estimating Standby Generation of 215 GWh as shown in Appendix A.

- There is currently no regulatory mechanism to allow Hydro to recover additional costs associated with operating the additional Standby Generation. In the absence of regulatory relief, Hydro's net income will be reduced by $33.3 million in 2016 for net loss of $0.1 million based on the 2015 Test Year.
- Hydro is proposing a deferral mechanism to recover the cost of increased Standby Generation for the provision of reliable service to customers.

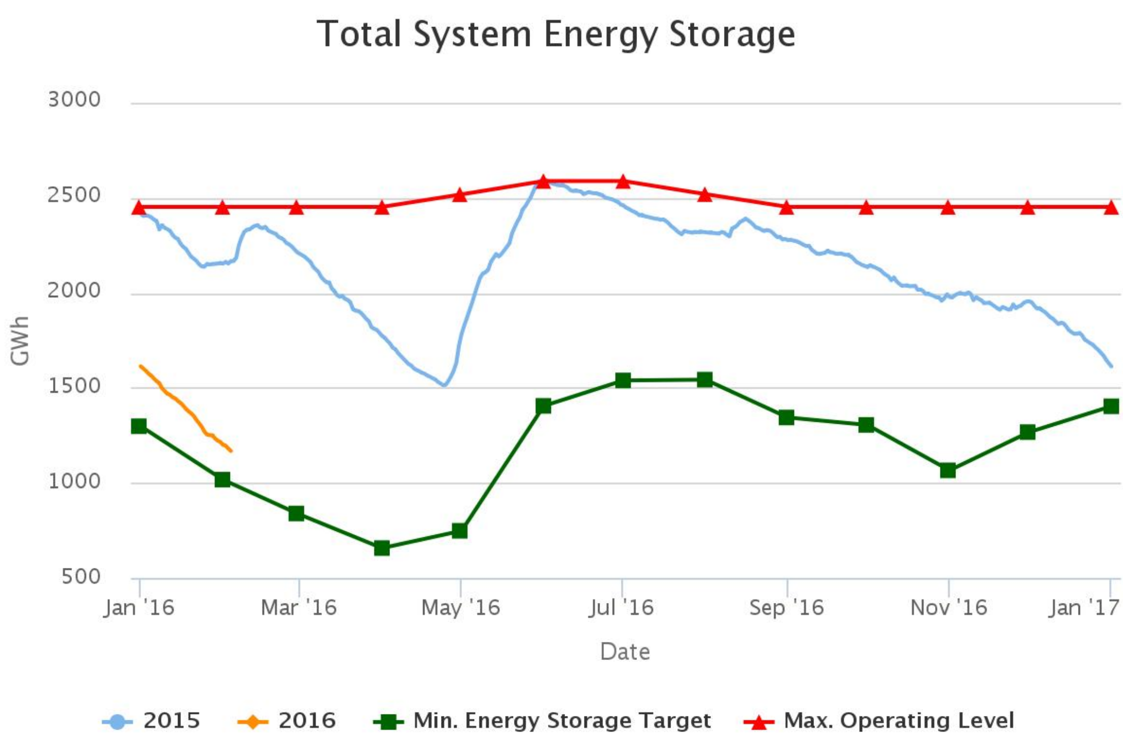
2.0 Low Hydrology: Effect on Hydraulic Production and Generation Mix

Hydro relies on precipitation to fill and maintain its reservoirs for hydraulic generation on the Island Interconnected system. Hydro reservoirs have been experiencing very low precipitation levels in the second half 2015 and in early 2016. Hydro's reservoirs were full in June 2015 and have been in decline since that time due to lower than average precipitation.

2.1 Low Reservoir Storage

Energy storage at Hydro's reservoirs has materially declined since September 2015, as shown in Chart 1. Hydro typically experiences high precipitation levels in the fall however, this did not occur in 2015. Currently, reservoir storage is at the second lowest level in 24 years. This storage level is the result of September to December 2015 inflows which were 24% below average and year to date 2016 inflows are at 26% of average.

Chart 1[2]



[2] Chart 1, minimum storage targets presented are for 2015.

2.2 Minimal Snowpack

Precipitation in the form of snowfall is also a critical part of the hydrology regime. Snow provides for runoff to the reservoirs post winter, and replenishes reservoirs in advance of the typically lower inflows of summer. For the season thus far, snowfall has also been low. Snowpack as of January 27, 2016 is well below typical end of winter levels, as noted in Table 1. Current low snowpack levels suggest that spring runoff in 2016 will result in limited reservoir recovery.

Table 1

Snowpack Data

Location	Typical [3] (mm)	Actual (mm)	Variance (mm)
Cat Arm	270	90	(180)
Victoria	180	93	(87)
Sandy Lake	205	96	(109)
Total	**655**	**279**	**(376)**

2.3 Low Recent Inflows

The cumulative effect of low reservoir storage, lack of fall precipitation, and low January snowpack is an expected material reduction in the amount of hydraulic generation available to Hydro in early 2016. Given current reservoir levels, in order for Hydro to achieve its 2015 Test Year forecast hydraulic production, and achieve 80% of maximum storage at the end of the spring runoff, Hydro would require approximately 28 precipitation events of 25 mm of rain (or approximately 25 cm of snow) during the 20 week period from February to June 2016.

Precipitation events that are mainly snow early in 2016 do not benefit Hydro's reservoirs until the spring runoff. Until that time, thermal generation has been, and will continue to be, dispatched to serve customers.

[3] Values shown in the 'Typical' column represent typical end of winter season snowpack levels. Hydro does not track snowpack data by month as snow surveys are completed twice a season. Values in Table 1 reflect snow gauge data from February 5, 2016.

Inflows experienced since September 2015 in comparison to historical averages are shown in Table 2. As noted below, actual inflow levels from September, 2015 to January, 2016 are slightly lower than Hydro's 1960/1961 dry period.

Table 2
Inflow Comparison

Inflows (GWh)	September	October	November	December	January	Total
Average	235	344	474	434	316	**1,803**
Actual	171	244	376	177	79	**1,047**
1960/1961	86	258	345	249	171	**1,109**

2.4 Reduction in Expected Hydraulic Production

Table 3 provides three hydroelectric generation scenarios for 2016 based on historical precipitation levels: average inflows, 1985 inflows, and 1961 inflows, in comparison to the 2015 Test Year.[4] The 1985 and 1961 scenarios are both unusually dry, where current inflows are also trending. As can be seen in the table, a very dry year can result in a Hydro-owned hydraulic generation nearing 1,000 GWh below average. A full scenario analysis by production source is included in Appendix A to this application.

Table 3
Hydraulic Production

Hydraulic Production (GWh)	Average Inflows	1985 Inflows	1961 Inflows
2015 Test Year	4,604	4,604	4,604
2016 Forecast	4,604	3,861	3,618
Variance	**0**	**(743)**	**(986)**

In addition, based upon the low water scenarios noted above, Hydro estimates that available power purchases from hydraulic sources, such as Nalcor Exploits, Star Lake, and Rattle Brook, could be lower by approximately 190 GWh compared to the 2015 Test Year, bringing the total island hydraulic reduction to about 1,200 GWh.

[4] 1961 inflows are the basis for Hydro's repeat critical dry sequence planning criteria. 1985 inflows represent the fourth driest year on record and a lower winter inflow year than 1961.

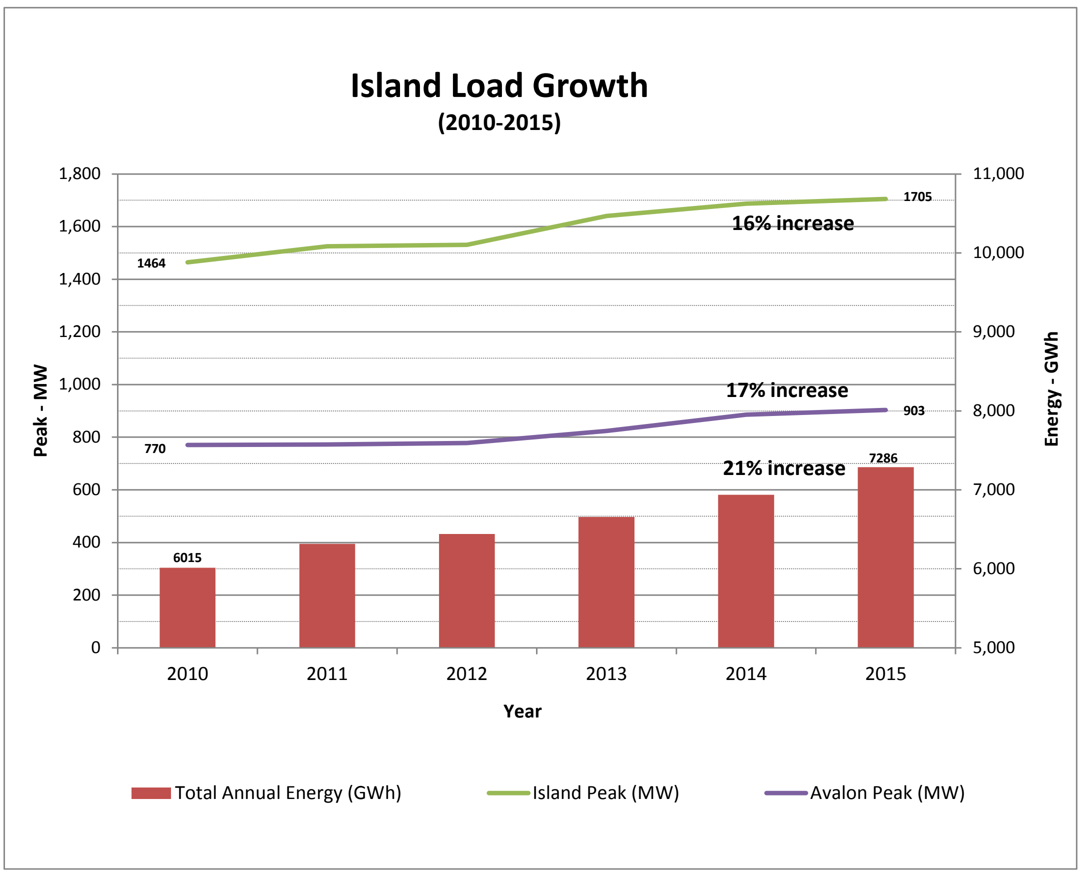
Reduced hydraulic production, both Hydro's own production and energy purchases from non-utility generators, is being replaced by thermal generation to meet customer energy requirements. Given the 2016 precipitation trend, Hydro estimates a total energy requirement of approximately 2,700 GWh from thermal generation sources.

Hydro notes that it expects Newfoundland Power's hydraulic generation will also be impacted in 2016, as the reduced inflows are generally province wide. To ensure the reliable supply to its customers, Hydro is required to ensure that it can replace any generation shortfall that occurs from any generation source.

2.5 Growing Customer Load

Customer energy requirements have been steadily increasing since 2010, as shown in Chart 2. Meeting customer load, combined with a dry year in 2016, requires increased thermal generation in Hydro's generation mix.

Chart 2



3.0 Increased Thermal Generation Required to Balance Low Hydrology

In response to low precipitation levels, Hydro has already proactively increased the amount of thermal generation in its supply mix so that it can continue to meet customer energy requirements. Any shortfall between the thermal requirement and the capability of the Holyrood TGS, which is impacted by planned maintenance, unplanned maintenance, upgrade work, and unit de-ratings at Holyrood TGS, must be replaced by Standby Generation.

3.1 Planned Holyrood TGS 2016 Unit Outages

There is a major capital project for Unit 3 in 2016 including a rewind of the Unit 3 rotor and the generator overhaul. This is in addition to normal annual planned maintenance outages for the Holyrood units. The current schedule is noted below in Table 4. This will ultimately impact the total annual energy capability of the Holyrood TGS.

Table 4

Planned Holyrood TGS Outages

Holyrood TGS	Mar-16	Apr-16	May-16	Jun-16	Jul-16	Aug-16	Sep-16	Oct-16	Nov-16
Unit 1							10 Weeks		
Unit 2					12 Weeks				
Unit 3				18 Weeks					

3.2 Unplanned Holyrood TGS Outages Affecting Generation Capability

Hydro's capital budget application notes the amount of energy required to be provide by the Holyrood TGS's in a firm hydraulic year (approximately 3,000 GWH) is generally in excess of the current forecasted requirement due to low hydrology (approximately 2,700 GWh).[5] However, as the Holyrood TGS reaches the end of life, Hydro's ability to operate all units at maximum capacity outside maintenance periods is limited, based on planned and unplanned required maintenance and upgrades. This is most recently evidenced by 2016 Unit 2 unavailability.

[5] Page 4 of Hydro's 2016 Capital Budget Application report "*Holyrood Overview*" states *"The production at Holyrood may vary from that forecasted for the 2015 to 2018 period depending on the hydrologic conditions which influence Hydro's hydraulic energy supply capability. During a high inflow period, production from the Holyrood plant would be kept at minimum levels, with units operated only as required for system capacity and Avalon Peninsula transmission reliability considerations. Production during this period could be less than 1,000 GWh annually. On the other hand, during a repeat of the critical dry sequence, annual required production from Holyrood would be significant, up to 3,000 GWh per year. This requires that all units be operated at maximum capacity outside of their annual planned and maintenance outage requirements.*"

In January 2016, Unit 2 of the Holyrood TGS experienced a number of boiler tube failures. Due to the age of these tubes, a number of sections failed as a result of reduced tube wall thickness. While Hydro has replaced the failed tubes as well as those with the next highest risk of failure, there remain a number of tubes with wall thicknesses below optimal levels in both Units 1 and 2. As a result, Hydro does not consider it appropriate to operate Units 1 and 2 at their maximum capacities until full replacement can be made during the annual maintenance outages of 2016. The emergency tube replacement and reduced maximum capacity affects the total energy output of Holyrood TGS in 2016.

3.3 Holyrood TGS Resultant Maximum 2016 Capacity

Given the status of the boiler tubes and the Holyrood TGS planned outages in 2016, the forecast maximum production from the Holyrood TGS in 2016 is significantly below the theoretical maximum GWh of approximately 3,000, as shown in Table 5.

Table 5

Holyrood TGS Capacity

Particulars	GWh
Holyrood TGS Maximum	2,996
Unit 2 January Outage	(98)
Holyrood TGS Deratings	(264)
Extended Unit 3 Maintenace Outage	(159)
2016 Forecast Production	**2,475**

3.4 Holyrood TGS Recent Historic Generation Capacity

Over the past 10 years, the average annual production at the Holyrood TGS has been approximately 1,000 GWh. The 10 year average Holyrood TGS production of 1,000 GWH is in contrast to 2015 Test Year forecast production of 1,593 GWh, and the approximately maximum 2,500 GWh Holyrood will contribute to the generation mix in 2016 due to low hydrology. Hydraulic and Holyrood TGS production in relation to Island Load over the past 10 years are presented in Table 6.[6]

[6] Remainder of system load provided by power purchases.

Table 6

Historic Production Levels

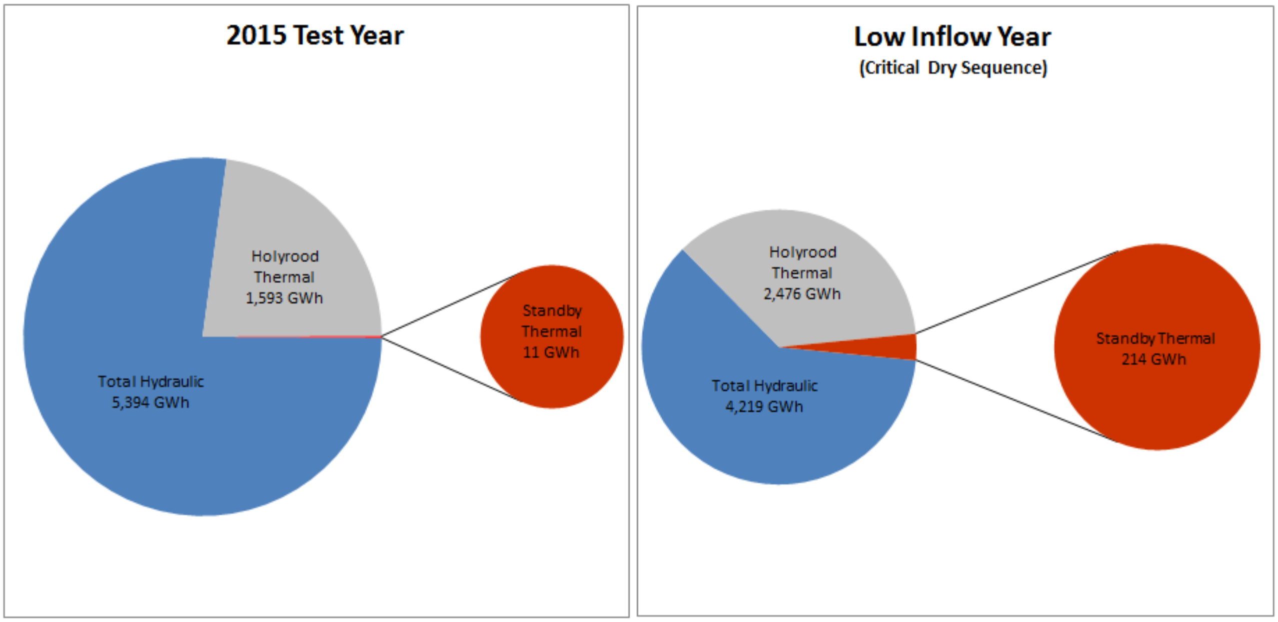
Year	Hydraulic Production (GWh)	HTGS Production (GWh)	Island Load (GWh)
2006	4,803	740	5,982
2007	4,689	1,256	6,389
2008	4,771	1,080	6,294
2009	4,200	940	6,113
2010	4,274	803	6,003
2011	4,512	885	6,287
2012	4,595	856	6,441
2013	4,688	957	6,658
2014	4,658	1,315	6,937
2015	4,824	1,458	7,286
Average	**4,601**	**1,029**	**6,439**

3.5 Standby Generation Requirement

As Holyrood TGS can contribute only 2,500 of the 2,700 GWh estimated to be required due to low hydrology, the shortfall must be made up using Standby Generation. Hydro is estimating that overall Standby Generation levels will be in excess of 200 GWh, as opposed to the 11 GWH forecast in the 2015 Test Year.

Chart 3 shows the impact of low hydraulic production in the 2015 Test Year scenario as well as a dry year scenario. In both scenarios, an increase in Holyrood TGS and Standby Thermal production is required to offset the reduction in available hydraulic production.

Chart 3[7]



3.6 Marginal Energy Production Cost

Under a low hydrology condition, the shortfall in thermal generation from the Holyrood TGS is being replaced by energy from Hydro's Standby thermal units. The forecast fuel cost of a kWh produced from these units is shown in comparison to the Holyrood TGS costs in Table 7.[8] [9]

Table 7

Marginal Production Costs

	Holyrood TGS	Interconnected Diesels	Hardwoods GT	Holyrood CT	Stephenville GT
Cents / kWh	10.61	19.43	21.10	21.40	27.70

Hydro plans to maximize production, where possible, at the Holyrood TGS in order to provide least cost service to customers. However, to ensure reliability of service under low hydrology conditions more

[7] Chart 3 excludes other power purchases, such as wind and co-generation, which are consistent in each scenario.
[8] The fuel cost at the Holyrood TGS is calculated using Hydro's proposed 2015 Test Year values of $64.41 per bbl of No. 6 fuel and a conversion factor of 607 kWh/bbl.
[9] Interconnected Diesels include St. Anthony, Hawkes Bay, and Blackstart Diesels.

energy will be generated from Standby thermal sources at a materially greater cost when compared to the Holyrood TGS.

4.0 Reliability and Operational Resiliency

4.1 Increased Reliability

Even under the Average Inflows scenario used in the test year, Hydro anticipates using increased Standby Generation in 2016 compared to the 2015 Test Year. Hydro operates its Standby Generation in the following situations:

1. In advance of single largest contingencies on the Avalon[10];
2. To meet spinning reserves requirements on the Island Interconnected system[10]; and
3. In response to unit and transmission line outages.

These operational practices are consistent with the findings of Liberty Consulting in their report on the events of March 4, 2015.[11]

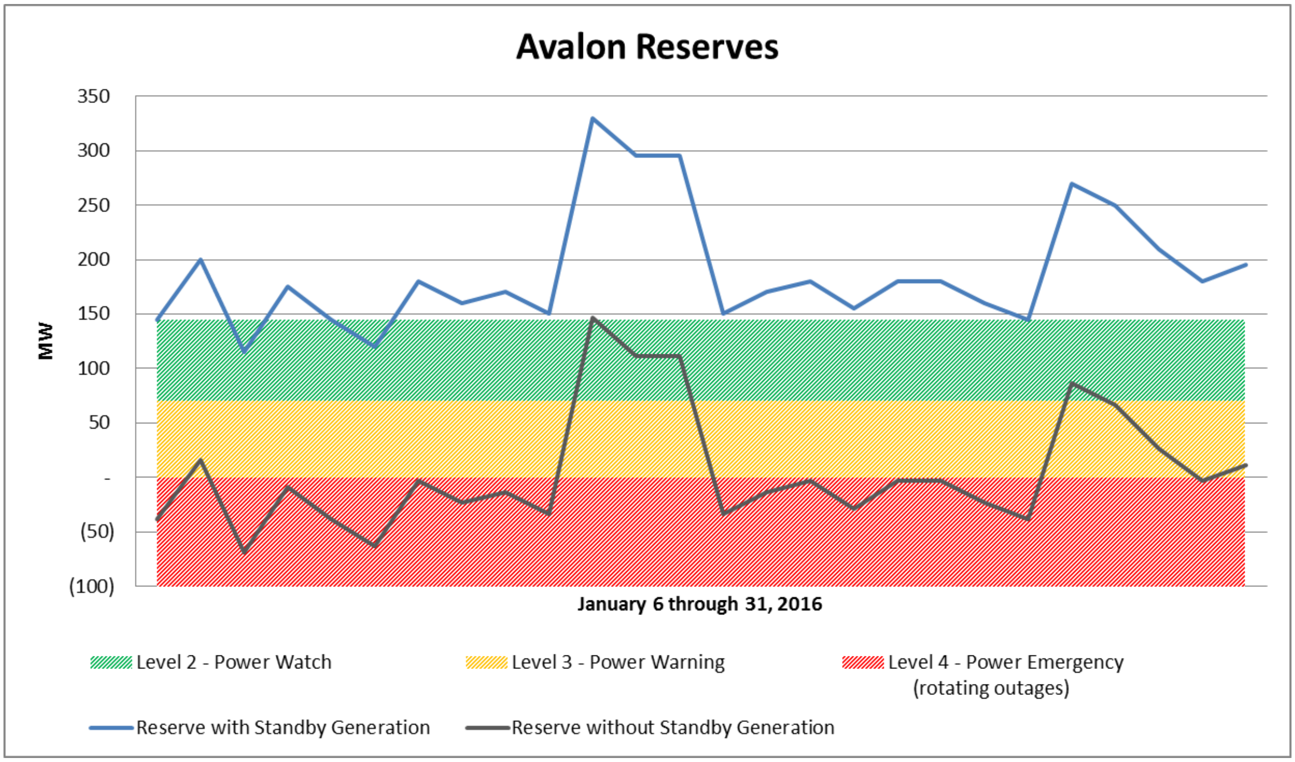
4.2 Increased Avalon and Energy Reserves

There are situations when the Standby Generation units are placed online to support system requirements. In January 2016, Hydro took Unit 2 at the Holyrood TGS out of service for emergency boiler tube replacement. During this time, Hydro's Standby Generation was used to provide reliable service to customers on the Avalon Peninsula as well as to provide energy to the system. Chart 4 illustrates the overall benefit that Standby Generation provides towards reliable supply on the Avalon Peninsula during January 2016.

[10] NLH 2013 GRA Final Submission, page reads "Included in these forecast fuel costs for 2015 is the cost of operating the new Holyrood CT. In contrast to forecast production levels included in the 2015 Test Year, Hydro has been running the Holyrood CT at minimum output levels during peak periods of the day to provide enhanced system reliability. This operational practice began in 2015 in response to enhanced reliability assessments following the March 4, 2015 outage event, and has resulted in increased fuel consumption at the Holyrood CT relative to the 2015 Test Year forecast."

[11] Liberty Consulting Review of the March 4, 2015 Voltage Collapse, Page 7 reads "Liberty continues to believe that Hydro should be significantly enhancing its capabilities to plan and manage reliability contingencies."

Chart 4



As shown in Chart 4, in the absence of running Hydro's Avalon Standby Generation, the Avalon Peninsula would have been in a Level 4 Power Emergency for the majority of January 2016 and Hydro would have instituted rolling customer outages on the Avalon. In addition to improved reliability afforded by running the Standby units, the use of Standby Generation in this manner has also injected energy into Hydro's system. This has resulted in reservoir storages which are higher than they otherwise would have been.

5.0 Financial Impact and Required Relief

Recovery of additional fuel costs not included in base rates is consistent with regulatory practice in this jurisdiction. For Hydro, the RSP is designed to, among other things, ensure recovery of increased No. 6 fuel costs in a low hydrology year. For Newfoundland Power, the Rate Stabilization Account (RSA) allows for deferral and recovery of all fuel costs in excess of base rates. However, Hydro currently has no deferral mechanism to allow for recovery of increased costs associated with operating its Standby Generation in the event of a shortfall in Holyrood TGS capability or to provide for reliable service to its customers.

In the absence of regulatory relief, Hydro's net income will be reduced by $33.3 million in 2016.[12] This would result in a net loss of $0.1 million based on the 2015 Test Year.[13]

Hydro is seeking approval for deferral of the financial impact of increased Standby fuel costs incurred in 2016 as a result of low hydraulic production, hydraulic purchases, and system reliability. The primary drivers of increased Standby fuel in 2016, i.e. low hydrology and increased reliability requirements due to load on the Avalon Peninsula, are beyond Hydro's control and therefore the utility should not be at risk for these costs. Hydro will, at every opportunity, look to minimize the cost of additional fuel in 2016 and provide least cost, reliable service to customers.

A proposed definition of the 2016 Standby Fuel Deferral is included in Appendix B to the Application. Forecast deferral balances based on three precipitation scenarios are included in Appendices C through E.

6.0 Conclusion

Approval of this Application by the Board will permit Hydro to defer fuel costs prudently incurred in the provision of service to customers due to low hydrology. It will also allow Hydro to provide reliable service to customers while still giving Hydro an opportunity to earn a just and reasonable return in 2016.

[12] Calculated deferral balance under 1961 inflows as shown in Appendix C.
[13] Hydro's proposed Net Income under a 2015 Test Year is $33.2 million.

Appendix A

2016 Inflow Scenarios	Average Inflows	1985 Inflows	1961 Inflows
Production (GWh)			
NLH Hydro			
Total Hydroelectric	**4,604.1**	**3,861.4**	**3,617.6**
NLH Thermal			
Holyrood TGS	**1,481.6**	**2,348.0**	**2,475.5**
NLH Standby			
Hardwoods Gas Turbine	6.4	6.4	6.4
Stephenville Gas Turbine	1.2	1.2	1.2
Holyrood CT	68.4	88.1	204.3
Holyrood Diesels	1.7	1.7	1.7
St. Anthony and Hawkes Bay Diesels	0.5	0.5	0.5
Total Standby	**78.2**	**97.9**	**214.1**
NLH Purchases			
Nalcor Exploits	588.0	472.9	472.9
Star Lake	142.2	117.4	117.4
Rattle Brook	14.8	11.4	11.4
CBPP Co-gen	52.2	52.2	52.2
St. Lawrence Wind	104.8	104.8	104.8
Fermeuse Wind	84.4	84.4	84.4
Total Purchases	**986.4**	**843.1**	**843.1**
Total Load	**7,150.4**	**7,150.4**	**7,150.4**

Appendix B

2016 Standby Fuel Deferral Account

This account shall be charged with the Standby Fuel Cost Variance incurred by Hydro on the Island Interconnected System in the 2016 calendar year.

It will apply to variations from Test Year fuel cost from the following supply sources:

- Holyrood Combustion Turbine;
- Hardwoods Gas Turbine;
- Stephenville Gas Turbine;
- St. Anthony Diesel Plant;
- Hawkes Bay Diesel Plant;
- Holyrood Blackstart Diesels; and
- Purchases from Newfoundland Power Thermal.

It will also include variances from Test Year fuel costs resulting from volume variance from the following hydraulic power purchases:

- Nalcor Exploits;
- Star Lake; and
- Rattle Brook.

The Standby Fuel Cost Variance will be determined by the following formula:

A + (B + C)

A = Test Year Standby Fuel Cost Variance for the defined fuel supply sources;

Where:

A = (Actual Standby Fuel Cost – Test Year Standby Fuel Cost)

B = Hydraulic Power Purchase Savings;

Where:

B = (Actual kWh Purchases – Test Year kWh Purchases) x (Test Year Purchase Cost in $ / kWh)

C = Fuel savings resulting from the reduction in generation at the Holyrood TGS.

Where:

C = D/E x F

D = Holyrood TGS Test Year average annual fuel cost per barrel;

E = Test Year fuel conversion factor (kWh/bbl); and

F = [(Actual kWh Standby Generation + Actual kWh Hydraulic Purchases) - (Test Year kWh Standby Generation + Test Year kWh Hydraulic Production)]

Disposition of any Balance in this Account
Hydro shall report to the Board the balance in this account on a quarterly basis and file an Application with the Board no later than March 1, 2017 regarding the disposition of any balance in this account.

2016 Standby Fuel Deferral Account
1961 Inflows

Line No.	Particulars ($)	Holyrood Combustion Turbine	Hardwoods Gas Turbine	Stephenville Gas Turbine	St. Anthony Diesel	Hawkes Bay Diesel	Blackstart Diesel	NP Thermal	Total
1	Forecast Fuel Costs	43,783,433	1,360,772	332,580	49,423	49,423	326,644	200,000	46,102,275
2	Test Year Fuel Costs	1,977,306	1,089,250	407,134	55,917	31,223	-	-	3,560,830
3	**A - Standby Fuel Cost Variance (Line 1 - Line 2)**								**42,541,445**

Line No.	Particulars ($)	Nalcor Exploits	Star Lake	Rattle Brook	Total
4	Forecast Power Purchases(kWh)	472,860,000	117,400,000	11,420,312	
5	Test Year Power Purchases (kWh)	633,500,000	142,180,000	15,000,000	
6	Test Year Cost ($ / kWh)	0.0400	0.0400	0.0836	
7	**B - Power Purchase Variance [(Line 4 - Line 5) x Line 6)]**	**(6,425,600)**	**(991,200)**	**(299,262)**	**(7,716,062)**
8	**C - Holyrood TGS Fuel Costs/(Savings) [(D/E)*F]**				**(1,536,323)**
9	**Standby Fuel Deferral Balance [A+(B+C)]**				**33,289,060**
10	D - Holyrood 2015 Test Year Average Fuel Cost (bbl)				64.41
11	E - Test Year Fuel Conversion Factor (kWh/bbl)				607
12	F - Annual kWh variance - 2016 Forecast vs. 2015 Test Year (kWh) (F1-F2)				(14,478,312)
13	F1 - Test Year Consumption (kWh)				801,940,000
14	F2 - Forecast Consumption (kWh)				816,418,312

2016 Standby Fuel Deferral Account
1985 Inflows

Line No.	Particulars ($)	Holyrood Combustion Turbine	Hardwoods Gas Turbine	Stephenville Gas Turbine	St. Anthony Diesel	Hawkes Bay Diesel	Blackstart Diesel	NP Thermal	Total
1	Forecast Fuel Costs	18,870,876	1,360,772	332,580	49,423	49,423	326,644	200,000	21,189,719
2	Test Year Fuel Costs	1,977,306	1,089,250	407,134	55,917	31,223	-	-	3,560,830
3	**A - Standby Fuel Cost Variance (Line 1 - Line 2)**								**17,628,889**

Line No.	Particulars ($)	Nalcor Exploits	Star Lake	Rattle Brook	Total
4	Forecast Power Purchases(kWh)	472,860,000	117,400,000	11,420,312	
5	Test Year Power Purchases (kWh)	633,500,000	142,180,000	15,000,000	
6	Test Year Cost ($ / kWh)	0.0400	0.0400	0.0836	
7	**B - Power Purchase Variance [(Line 4 - Line 5) x Line 6)]**	**(6,425,600)**	**(991,200)**	**(299,262)**	**(7,716,062)**
8	**C - Holyrood TGS Fuel Costs/(Savings) [(D/E)*F]**				**10,798,139**
9	**Standby Fuel Deferral Balance [A+(B+C)]**				**20,710,966**
10	D - Holyrood 2015 Test Year Average Fuel Cost (bbl)				64.41
11	E - Test Year Fuel Conversion Factor (kWh/bbl)				607
12	F - Annual kWh variance - 2016 Forecast vs. 2015 Test Year (kWh) (F1-F2)				101,761,688
13	F1 - Test Year Consumption (kWh)				801,940,000
14	F2 - Forecast Consumption (kWh)				700,178,312

2016 Standby Fuel Deferral Account
Average Inflows

Line No.	Particulars ($)	Holyrood Combustion Turbine	Hardwoods Gas Turbine	Stephenville Gas Turbine	St. Anthony Diesel	Hawkes Bay Diesel	Blackstart Diesel	NP Thermal	Total
1	Forecast Fuel Costs	14,661,847	1,360,761	332,580	49,423	49,423	326,639	200,000	16,980,672
2	Test Year Fuel Costs	1,977,306	1,089,250	407,134	55,917	31,223	-	-	3,560,830
3	**A - Standby Fuel Cost Variance (Line 1 - Line 2)**								**13,419,842**

Line No.	Particulars ($)	Nalcor Exploits	Star Lake	Rattle Brook	Total
4	Forecast Power Purchases(kWh)	587,970,000	142,190,000	14,800,000	
5	Test Year Power Purchases (kWh)	633,500,000	142,180,000	15,000,000	
6	Test Year Cost ($ / kWh)	0.0400	0.0400	0.0836	
7	**B - Power Purchase Variance [(Line 4 - Line 5) x Line 6)]**	**(1,821,200)**	**400**	**(16,720)**	**(1,837,520)**
8	**C - Holyrood TGS Fuel Costs/(Savings) [(D/E)*F]**				**(2,321,519)**
9	**Standby Fuel Deferral Balance [A+(B+C)]**				**9,260,803**
10	D - Holyrood 2015 Test Year Average Fuel Cost (bbl)				64.41
11	E - Test Year Fuel Conversion Factor (kWh/bbl)				607
12	F - Annual kWh variance - 2016 Forecast vs. 2015 Test Year (kWh) (F1-F2)				(21,878,000)
13	F1 - Test Year Consumption (kWh)				801,940,000
14	F2 - Forecast Consumption (kWh)				823,818,000

IN THE MATTER OF the *Electrical Power Control Act,* R.S.N.L. 1994, Chapter E-5.1 (the *EPCA*) and the *Public Utilities Act*, R.S.N.L. 1990, Chapter P-47 (the *Act*), and regulations thereunder;

AND IN THE MATTER OF an Application by Newfoundland and Labrador Hydro (Hydro) pursuant to section 70 of the *Act*, for approval of a deferral account for diesel fuel consumed in 2016 to provide capacity and energy to the Island Interconnected System

AFFIDAVIT

I, John MacIsaac, of the City of St. John's, in the Province of Newfoundland and Labrador, Professional Engineer, **MAKE OATH AND SAY AS FOLLOWS**:

1. I am employed by Newfoundland and Labrador Hydro, the Applicant herein, in the capacity of President, and as such I have knowledge of the matters and things to which I have herein deposed, and make this Affidavit in support of the Application.

2. I have read the contents of the Application and they are correct and true to the best of my knowledge, information and belief.

SWORN to before me at St. John's, in the Province of Newfoundland and Labrador, this 5th day of February, 2016, before me:

Barrister – NL

John MacIsaac

(DRAFT ORDER)
NEWFOUNDLAND AND LABRADOR
BOARD OF COMMISSIONERS OF PUBLIC UTILITIES

AN ORDER OF THE BOARD

NO. P.U. __ (2016)

IN THE MATTER OF the *Electrical Power Control Act*, RSNL 1994, Chapter E-5.1 (the *EPCA*) and the *Public Utilities Act*, RSNL 1990, Chapter P-47 (the *Act*), and regulations thereunder;

AND IN THE MATTER OF an Application by Newfoundland and Labrador Hydro (Hydro) pursuant to section 70 of the *Act*, for approval of a deferral account for diesel fuel consumed in 2016 to provide capacity and energy to the Island Interconnected System

WHEREAS the Applicant is a corporation continued and existing under the *Hydro Corporation Act*, *2007*, is a public utility within the meaning of the Act and is subject to the provisions of the *Electrical Power Control Act*, 1994; and

WHEREAS in the second half of 2015 and in the first month of 2016 there has been extremely low inflows in the Applicant's reservoirs and in the reservoirs of other hydro-electric producers on the island Interconnected System thereby requiring a greater proportion than usual of energy to be generated from thermal generating resources; and

WHEREAS due to the aforementioned hydrological situation, limitations in the output of Hydro's Holyrood Thermal Generating Station, increased customer load, and the need to provide reliable service to its customers, Hydro has needed and will continue to need to generate and acquire more energy than expected from other available thermal generating resources (combustion turbines and diesel generators, both which consume diesel fuel), which generating resources are more typically used as standby generation for capacity and peaking purposes; and

WHEREAS variations that occur in Hydro's fuel costs associated with No. 6 fuel consumed at the Holyrood Thermal Generation Station are stabilized through the Rate Stabilization Plan however that stabilization account does not address variations in the cost of fuel incurred to operate the standby generating resources; and

WHEREAS the fuel costs being incurred by Hydro for the foregoing reasons are material, are higher than forecast, and pose a financial hardship to Hydro; and

WHEREAS on February 5, 2016 the Applicant filed an Application with the Board requesting approval of a deferral account to permit the deferral for later recovery of these standby generation fuel costs; and

WHEREAS the Board is satisfied that the deferral account requested by Hydro in the Application should be approved.

IT IS THEREFORE ORDERED THAT:

1. The standby fuel cost deferral account applied for as set out in its Application is approved.

2. Hydro shall pay all expenses of the Board arising from this Application.

DATED at St. John's, Newfoundland and Labrador, this ____day of ___________, 2016.

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A REPORT TO

THE BOARD OF COMMISSIONERS OF PUBLIC UTILITIES

REGISTERED PROFESSIONAL ENGINEER PEG Newfoundland and Labrador TODD C. COLLINS SIGNATURE August 29/16 DATE NEWFOUNDLAND & LABRADOR	Electrical
	Mechanical
	Civil
	Protection & Control
	Transmission & Distribution
	Telecontrol
	System Planning

Combustor Inspection Major and Overhaul

Holyrood Combustion Turbine

August 29, 2016

newfoundland labrador hydro
a nalcor energy company

SUMMARY

This project is to complete a combustor inspection major (CI) and overhaul on the 123.5 MW Holyrood Siemens 501D5A combustion turbine (CT). Siemens, the original equipment manufacturer (OEM), recommends that an overhaul be completed when the total equivalent starts (ES) on the turbine reaches 400 for units operating in a cyclic duty or peaking application. The Holyrood CT has operated more than initially expected in 2015 and 2016, and it is anticipated that the Holyrood CT will reach this milestone requiring the inspection and overhaul by February 2017. It was originally anticipated that the unit would not reach this level of operation until the spring of 2018.

The project scope of work includes the following:

1. Removal of the turbine combustion section access covers and inspection of the combustor components for damage;
2. Removal and installation of replacement combustor baskets, combustor transition cylinders, fuel nozzles, and replacement of the row 1 turbine blade vane segments, as required; and
3. Completion of OEM recommended modifications to the turbine exhaust bearing venting system.

This project is necessary to maintain reliable operation of the Holyrood CT plant.

The budget estimate for this project is $4,738,300. The project is expected to be completed over the period October 1, 2016 to December 31, 2016, with the unit being returned to service at the end of November and the project close-out tasks taking place in December.

TABLE OF CONTENTS

1 INTRODUCTION

The Holyrood CT, located at the Holyrood Generating Station, is a 123.5 MW gas turbine generating unit that was constructed in 2014, commissioned in early 2015, and placed in service in February 2015. It provides electricity to the Island Interconnected System. Figure 1 is a diagram of the Provincial generation and transmission grid showing the location of the Holyrood Generating Station site.

Figure 1: Provincial Generation and Transmission Grid

The Holyrood CT provides several critical functions in reliably supplying customer demand requirements. It is operated to support spinning reserves on the Island Interconnected System and provides a critical backup in the event of a contingency, such as the loss of a major generating unit or the loss of a major transmission line. The Holyrood CT, due to its strategic location, also provides power to the Avalon Peninsula which is heavily reliant on the transfer of power over transmission lines from outside of the Avalon Peninsula and the production of power from the Holyrood Thermal Generating Station (HTGS). In addition, it is used to facilitate planned generation and Avalon Peninsula transmission outages.

Figure 2 is an image of the Holyrood CT plant.

Figure 2: Holyrood Combustion Turbine Plant

Figure 3 is an image of the combustion turbine at the Holyrood combustion turbine plant.

Figure 3: Holyrood Siemens Combustion Turbine

2 BACKGROUND

The internal components of a gas turbine wear differently when comparing a continuous duty application to a cyclic duty application where there are more frequent starts and stops. Thermal fatigue is the primary contributor to loss of life for peaking or cyclic loaded machines, whereas creep, oxidation, and corrosion are the contributors to loss of life for continuous duty or base loaded machines. For that reason, Siemens, the original equipment manufacturer (OEM), has developed maintenance schedules for this unit based on the number of ES or equivalent base hours (EBH) of operation, which is further detailed in Appendix A. Total ES takes into account the effects of cyclic thermal stresses caused by starts, unit trips, and load changes during operation and is a function of successful starts, fired aborts, unit trips while under load, and instantaneous load changes for a given type of fuel. Thus, the number of equivalent starts will be more than the number of actual starts.

Refer to Appendix A for further information related to the calculation of equivalent starts. Total EBH considers the effects of run time and temperature during operation and is a function of running hours for a given type of fuel. For this model of combustion turbine, operating on distillate fuel, Siemens recommends that an inspection and overhaul of the combustion section be completed when one of the following criteria is met:

1. Total Equivalent Starts = 400; or
2. Total Equivalent Base Hours = 8000.

Based on the initial anticipated operation of the Holyrood CT, a maintenance strategy was developed based on CT unit achieving the specified number of equivalent starts rather than equivalent hours due to the cyclic nature of its operation, primarily in a peaking role.

2.1 Asset Management Strategy

The asset management strategy for the Holyrood combustion turbine is based on the recommendations of the OEM and includes four distinct points of intervention based on achieving either the number of ES or the number of EBH specified. These four interventions include:

1. When the unit operation has reached 100 ES or 2000 EBH, a combustor minor, a preventative maintenance inspection performed using a borescope, is recommended. This inspection primarily consists of non-intrusive visual inspections and tests, but does not normally include turbine component replacement. This inspection was completed in 2016 with findings within the limits for the operation of the unit. Based on the current forecast operation of the unit, it is expected that this inspection will be performed annually.

2. When the unit operation has reached 400 ES or 8000 EBH, a combustor CI is recommended. This preventative maintenance intervention consists of the removal of all combustor and turbine end components that are accessible

without removing the turbine covers. The fuel nozzles, support housings, baskets, transitions and seals are replaced.

3. When the unit operation has reached 800 ES or 24000 EBH, a hot gas path inspection is recommended. This preventative maintenance intervention consists of the work scope included in the combustor inspection major as well as an inspection of the turbine rows 1-4 blades, vanes and ring segments with replacement as required. This scope of work is focused on the most highly stressed section of the CT's turbine section.

4. When the unit operation has reached 1600 ES or 48,000 EBH, a major inspection is recommended. This preventative maintenance intervention consists of the work scopes included in the CI major and the hot gas path inspection, as well as the inspection of the compressor vanes, blades and seals with replacement as required. This scope of work is focused on the parts replacement required for recovery of optimum unit performance.

Table 1: OEM Recommended Inspection Intervals

Total Equivalent Starts (ES)	**Inspection Type Recommended**
100	Combustor Minor
400	Combustor Major
800	Hot Gas Path
1200	Combustor Major
1600	Major

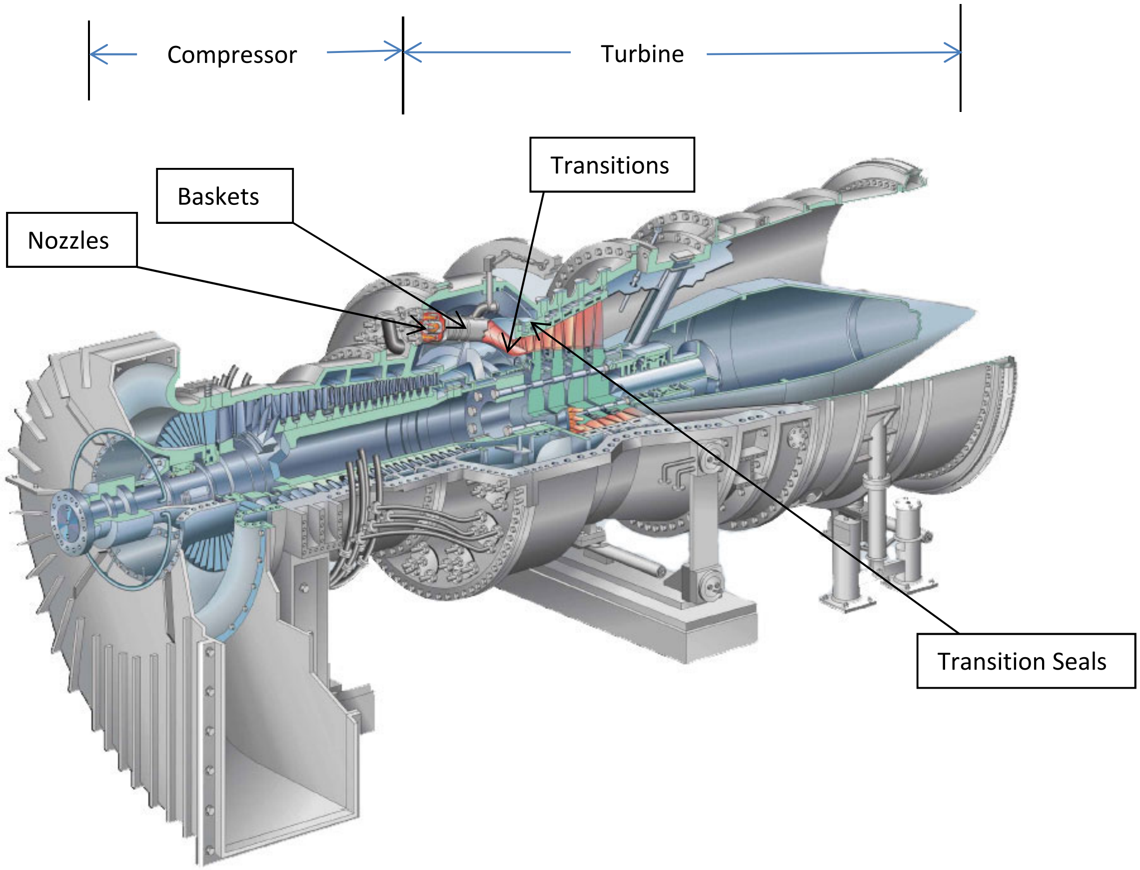

Figure 4: Cutaway view of the Siemens W501D5A combustion turbine

These interventions comprise a complete inspection and maintenance cycle for the combustion turbine and are summarized in Table 1 below. These interventions are required to be repeated at the specified intervals over the life of the unit. Based on the current operating forecast for the Holyrood CT, it is expected that the next intervention, a turbine hot gas path inspection, will be required to be completed in the fall of 2019.

2.2 Asset Maintenance Timing

Prior to the Holyrood CT being placed in service in winter 2015, a forecast was prepared for the operation of the CTs on the Island Interconnected System. The forecast requirements for the CTs were determined based on average forced outage rates of 10% for the Holyrood thermal units and 1% for Hydro's hydraulic units, and in consideration of the peak load forecast and Hydro's typical load duration curve.

In developing forecast operating requirements for the CTs, Hydro determined the expected number of operating hours required and the level of production. The total energy was then allocated to each of the required units on a prorated basis based on the generator maximum continuous rating.

Hydro's forecast for combustion turbine production also assumed that each plant would be exercised at rated output for one hour per month during the non-winter period for testing and for ensuring availability. These units were assumed to be exercised for four hours during each winter month (approximately once per week) for winter readiness and storm preparedness[1].

Although the expected energy production and an estimate of the number of annual operating hours required for peaking (using an assumption for average loading) is able to be provided using this methodology, the expected number of actual starts cannot be readily determined. To estimate the expected number of actual starts, the average operating hours per start for peaking operation was assumed to be four, excluding the hours for testing purposes.

The initial forecasted annual operation requirements of the Holyrood CT, as determined during the fall of 2014, are summarized in Table 2 below. This was based on anticipated annual peaking and testing requirements to the end of 2017.

[1] Reference Hydro's 2013 Amended GRA filing, Regulated Activities, Section 2.6.1, pages 2.77 – 2.78

Table 2: Initial Holyrood CT Forecasted Operating Requirements 2015 - 2017

Year	Hours	Equivalent Hours (EBH)	Actual Starts	Equivalent Starts (ES)
2015	184	239.2	64	83.2
2016	294	382.2	92.5	118.9
2017	444	577.2	129	167.7

Based on this initial forecasted operation of the Holyrood CT from its in service date to the end of 2017, it was originally anticipated that the Holyrood CT would accumulate an average of approximately 100 ES per year and require a CI and overhaul in the spring of 2018. As such, this was the planned first major inspection date. The actual operating requirements and the resultant equivalent starts and hours are presented in Table 3 below.

Table 3: Actual Holyrood CT Operating Requirements 2015 – June 2016

Year	Actual Hours	Equivalent Hours (EBH)	Actual Starts	Equivalent Starts (ES)
2015	823	1069.9	115	250.9
2016 (to June 30)	1494	1942.2	43	65

2.3 Increase in Equivalent Starts Compared to Initial Forecasted Estimate

After the March 4, 2015 power outage event, Hydro implemented practices and strategies which impacted the utilization of standby generation on the Island Interconnected System, especially on the Avalon Peninsula. Specifically, Hydro commenced the practice of operating standby generating units that support the Avalon in advance of Avalon transmission or generation contingencies, rather than starting them after the event has occurred[2]. This practice, in an effort to positively impact system reliability, began in late March 2015.[3]

[2] Consistent with the recommendations of Liberty Consulting in the Review of the March 4, 2015 Voltage Collapse, page 7: "Liberty continues to believe that Hydro should be significantly enhancing its capabilities to plan and manage reliability contingencies."
[3] Hydro previously advised the Board of this in Response A9 of its May 15, 2015 submission to the Board answering the questions of their April 21, 2015 letter related to the March 4 events.

An example of this was the total plant outage at the Holyrood Thermal Generating Station in August 2015, which was required to complete common plant equipment maintenance. Hydro operated the Holyrood CT at minimum output levels for the peak periods of the day to support the Avalon transmission and provide enhanced system reliability. The duration of the total plant outage was 18 days during which the Holyrood CT was operated almost daily, thus accumulating 18 actual starts.

In November 2015, TL201 was taken out of service for planned maintenance. During the outage to TL201, the Holyrood CT was operated daily to reduce the load on TL217, the line which remained in service to guard against another Avalon contingency.

In January and February of 2016, reheater tube failures on Units 1 and 2 at the HTGS resulted in the requirement to further operate the Holyrood CT to replace the generation normally provided by these units, one of its intended purposes, in support of Island generation and Avalon reserves. The Holyrood CT operated 608 hours in January and 632 hours in February to facilitate the outages required to repair HTGS Units 1 and 2 and return them to service. As the Holyrood CT operated almost continuously during the period January 6 to February 27, 2016, this operation did not contribute directly to the requirement to advance the planned maintenance intervention. However, the resulting de-rating of both HTGS Units 1 and 2 to 120 MW from 170 MW resulted in a loss of 100 MW of generating capability on the system. This resulted in continued requirement for operation of the gas turbines through daily peak demand periods in order to support Island and Avalon reserves. The Holyrood CT, being the largest of the gas turbines, was utilized more often due to system requirements resulting from the significant loss of thermal generation.

Up to the end of 2015, the Holyrood CT had actually operated 788 hours and accumulated 94 actual starts over ten months of service, post commissioning. During the period January 1 to June 30, 2016, the Holyrood CT accumulated an additional 43 actual starts and 1494 operating hours.

The monthly ES data from January 2015 to June 2016 is presented in Table 4 below. The equivalent starts accumulated in January and February 2015 were almost exclusively incurred during commissioning.

Table 4: Holyrood CT ES[4] and EBH by Month

Month	ES	EBH
January 2015	24.7	13
February	15.6	46.8
March	44.2	239.2
April	24.7	65
May	26	33.8
June	11.7	7.8
July	3.9	2.6
August	39	254.8
September	6.5	66.3
October	2.6	18.2
November	28.6	250.9
December	23.4	189.8
January 2016	3.9	791.7
February	2.6	825.5
March	28.6	140.4
April	23.4	174.2
May	5.2	22.1
June	1.3	2.6
Total	**315.9**	**3144.7**

Hydro's current operating forecast for the Holyrood CT from July 2016 to April 2017 is presented in Table 5 below. This data is based on required operating hours and does not include any estimate of equivalent starts resulting from unit trips, load changes, etc.

[4] Refer to Appendix A for equivalent starts ES calculations.

Table 5: Holyrood CT Operating Forecast July 2016 - April 2017

Month	ES	EBH
July 2016	2.6	2.6
August	2.6	2.6
September	2.6	2.6
October	2.6	2.6
November	7.8	9.1
December	16.6	27.3
January 2017	31.1	122.2
February	27	79.3
March	21.6	65
April	10.9	41.6
Total	**125.5**	**354.9**

The total EBH from Tables 4 and 5 is 3499.68 as compared to a total EBH of 8000 when an overhaul is recommended by Siemens. However, the total ES from Tables 4 and 5 is 441.4 up to April 2017, which indicates that the Holyrood CT is expected to reach the specified number of equivalent starts recommended to perform a CI and overhaul in February 2017. Performing the work in February would not be acceptable since the Holyrood CT would be out of service during critical production time.

Hydro's forecast of equivalent starts and equivalent base hours of the Holyrood CT for the period 2017 to 2019 is provided in Table 6, below. This estimate is based on forecasted operational requirements only and does not include any allowances for failed starts, trips from load, etc. This also assumes that the HTGS, in combination with the standby units, will supplement hydro and purchases to meet customer load throughout the forecast period.

Table 6: Holyrood CT Forecasted ES and EBH, 2017 to 2019

Year	Equivalent Starts	Equivalent Base Hours
2017	118.3	708.5
2018	130	533
2019	128.7	494
Total	**377**	**1735.5**

Based on the current forecast, the next major maintenance intervention (Hot Gas Path) is expected to occur in the fall of 2019, when the Holyrood CT is expected to have accumulated a further 377 equivalent starts.

3 PROJECT DESCRIPTION

This project includes a CI and overhaul on the Siemens W501D5A engine located at Holyrood. The CI involves the removal of all combustor and turbine end components that are accessible without removing the turbine covers. These parts will then be cleaned, inspected, and replaced, where necessary. Components that are not removable without removing the turbine covers will be inspected in place. The project will include the following scope of work:

1. Removal and replacement of the combustor components including:
    a. combustor transition sections;
    b. combustor baskets;
    c. combustor transition cylinders and V-band clamps; and
    d. fuel nozzles.
2. Removal of the row 1 vane segments, inspect the row 1 turbine blades, and replacement of row 1 vane segments, as required; and
3. OEM recommended modification of the exhaust bearing vacuum line and replacement of the orifice in the bearing lube oil supply line.

The OEM has recommended modifications to the turbine exhaust bearing lube oil system to enhance the operation of this system based on operating experience with the type of bearing which is installed on this unit, which are able to be completed during the required outage. The outage required to complete this work is expected to be of two weeks duration.

4 JUSTIFICATION

The availability and reliability of the Holyrood CT plant is critical for the generation support of the Island Interconnected and Avalon Systems.

4.1 Existing System

The major components of the Holyrood CT plant include the gas turbine engine, generator, starting package, air intake structure, exhaust stack, as well as auxiliary systems such as lube oil, fuel, compressed air, electrical, water treatment, and controls. Structures such as buildings and equipment enclosures comprise the balance of plant that make up the facility.

The Holyrood CT consists of a Siemens W501D5A engine that is directly coupled to a Siemens SGEN-100A-2P generator. It has a starting package that is coupled to the other end of the generator rotor. The starting package includes a 2050 HP motor and a clutch. During the initial start-up, the starting package accelerates the generator and turbine rotors up to approximately 50% of its rotating speed. At that point, the clutch disengages the starting package and ignition occurs in the combustion section of the Holyrood CT. The Holyrood CT uses a combination of No. 2 light fuel oil, compressed air, and ambient combustion air to produce hot gases that are fed into the turbine, causing it to rotate. Demineralized water is also injected into the combustion section of the turbine in order to reduce NO_X emissions during operation.

There has been no major work or upgrades to the Holyrood CT since being placed service in February 2015 and it has been a reliable addition to Hydro's generation fleet.

4.2 Operating Experience

The Holyrood CT has been in service since late February 2015 providing critical generation support to the Island Interconnected System and to the Avalon Peninsula. The table below provides the operating history of the Holyrood CT from March 1, 2015 to June 30, 2016.

Table 7: Holyrood CT Operating Hours and Actual Starts 2015 and 2016

Year	Total Operating Hours	Total Actual Starts
2015 (March 1 to December 31)	788	94
2016 (to June 30)	1494	43

4.2.1 Reliability Performance

This project is necessary to maintain the generating equipment in its optimal operating condition for Hydro to provide safe, least-cost, reliable electrical service to its customers.

4.2.1.1 Outage Statistics

Table 8 below lists the 2015 to 2016 average capability factor, utilization forced outage probability (UFOP) and failure rate for the Holyrood CT compared to all of Hydro's gas turbine units (2011 to 2015) and the latest Canadian Electrical Association (CEA) average (2010 to 2014).

Table 8: Holyrood CT One Year Average (2015-2016) All Causes

Unit	Capability Factor (%)[5]	UFOP (%)[6]	Failure Rate[7]
Holyrood CT (2015/2016)*	96.21	2.49	19.21
CEA (2010-2014)	84.16	9.52	66.60
* From March 1, 2015 to May 31, 2016			

[5] Capability Factor is defined as unit available time. It is the ratio of the unit's available time to the total number of unit hours.
[6] UFOP is defined as the Utilization Forced Outage Probability. It is the probability that a generation unit will not be available when required. It is used to measure performance of standby units with low operating time such as gas turbines.
[7] Failure Rate is defined as the rate at which the generating unit encounters a forced outage. It is calculated by dividing the number of transitions from an operating state to a forced outage by the total operating time.

4.2.2 Legislative or Regulatory Requirements

There are no legislative or regulatory requirements associated with this project.

4.2.3 Safety Performance

An in service failure of the unit due to not completing the combustor inspection and overhaul within the recommended timeline is not expected to create a safety hazard for Hydro employees.

4.2.4 Environmental Performance

This project does not impact environmental performance.

4.2.5 Industry Experience

Siemens has indicated that the majority of utilities that are operating this type of CT have adopted the recommended maintenance strategy based on total ES and EBH criteria outlined above in Section 2 – Background.

4.2.6 Vendor Recommendations

Siemens recommends that a CI and overhaul be completed when the total ES on the combustion turbine reaches 400. The Holyrood CT is expected to reach this critical milestone by February 2017.

4.2.7 Maintenance or Support Arrangements

Normal routine maintenance work is performed by Hydro personnel. In addition, contracted resources are used to perform specialty work and services such as maintenance of the fire protection systems, HVAC systems, etc.

4.2.8 Historical Information

The Holyrood CT plant has been in service for approximately 18 months providing critical generation capability to the Island Interconnected System and in support of transmission and generation on the Avalon Peninsula.

4.2.9 Anticipated Useful Life

A gas turbine system has an anticipated service life of 35 years. This assumes that routine maintenance and overhauls are completed in accordance with OEM recommendations.

4.3 Forecast Customer Growth

Forecasted customer growth is not applicable to this project.

4.4 Development of Alternatives

The following alternatives were considered related to the proposed project.

1. Continue to operate the Holyrood CT until the end of the 2016/2017 winter period and perform the combustor inspection and overhaul in the spring of 2017;
2. Continue to operate the Holyrood CT until it has accumulated 400 equivalent starts, as recommended by the OEM and perform the combustor inspection and overhaul at that time; and
3. Perform the combustor inspection and overhaul prior to the winter of 2016/2017.

4.5 Evaluation of Alternatives

<u>Alternative 1</u>

Continuing to operate the Holyrood CT until the end of the winter 2016/2017 operating period is expected to result in operation past the recommended maintenance interval for this unit by approximately 10%, thus imposing a risk on the CT's reliability including the risk of an in service failure. With little operating history, a complete combustor inspection is required to establish the patterns of wear and gather important information related to future operation of the unit. Operating the Holyrood CT past the OEM-recommended maintenance interval without this information is not recommended. Hydro does not propose this alternative as an appropriate course of action.

Alternative 2

Continuing to operate the Holyrood CT until it has accumulated 400 equivalent starts is expected to result in a requirement to perform this work during the peak winter operating period. Currently, the unit is expected to reach this milestone in February 2017. An outage at this time of year would remove this unit from the system and from its role in supporting the system at a critical time of year. Hydro does not propose this alternative as an appropriate course of action.

Alternative 3

Completing the CI and overhaul of the Holyrood CT prior to the winter operating season ensures a position of winter readiness and reduces the risk of a forced outage during the critical operation period.

Hydro proposes that Alternative 3 be approved, that the appropriate alternative is to complete the CI and overhaul of the Holyrood combustion turbine prior to winter 2016/2017.

4.5.1 Energy Efficiency Benefits

There are no energy efficiency benefits that can be attributed to this project.

4.5.2 Economic Analysis

An economic analysis was not performed in this instance as Hydro proposes the unit must have this work performed prior to the winter operating season.

5 CONCLUSION

This project is justified on the requirement to maintain the generating equipment in its optimal operating condition for Hydro to provide safe, least-cost, reliable electrical service to its customers. Siemens recommends that a CI and overhaul be completed on the Holyrood CT when the total equivalent starts reaches 400. Hydro expects that the Holyrood CT will reach this critical milestone in February 2017. The purpose of the CI and overhaul is to maintain the original design specifications so that the Holyrood CT can safely, efficiently, and reliably meet system demands until the next overhaul. It will also identify any unusual findings that, if not corrected, could lead to premature failure of the equipment. Siemens' recommended maintenance schedule for this unit, based on equivalent starts, involves maintenance interventions every 400 equivalent starts which vary in scope based on the expected service life of specific turbine and compressor components.

The Holyrood CT provides several critical functions in reliably supplying customer demand requirements. It is operated to support spinning reserves on the Island Interconnected System and provides a critical backup in the event of a contingency such as the loss of a major generating unit or the loss of a major transmission line. The Holyrood CT also provides power to the Avalon Peninsula which is heavily reliant on the transfer of power over transmission lines outside of the Avalon Peninsula, as well as the production of power from the Holyrood Thermal Generation Station. In addition, it is used to facilitate planned generation and Avalon Peninsula transmission outages.

5.1 Budget Estimate

The budget estimate for this project is shown in Table 9.

Table 9: Project Budget Estimate

Project Cost: *($ x1,000)*	**2017**	**2018**	**Beyond**	**Total**
Material Supply	0.0	0.0	0.0	0.0
Labour	242.3	0.0	0.0	242.3
Consultant	0.0	0.0	0.0	0.0
Contract Work	3,686.7	0.0	0.0	3,686.7
Other Direct Costs	0.0	0.0	0.0	0.0
Interest and Escalation	23.5	0.0	0.0	23.5
Contingency	785.8	0.0	0.0	785.8
TOTAL	**4,738.3**	**0.0**	**0.0**	**4,738.3**

The above budget is based on a budgetary estimate for Hydro personnel to perform a portion of the work, and there are tasks that must be completed by contractor personnel due to the highly specialized nature of the work.

5.2 Project Schedule

The anticipated project schedule is shown in Table 10. These are tentative dates and reflect an early approval by the Board of Commissioners of Public Utilities (the Board).

Table 10: Project Schedule

Activity		Start Date	End Date
Planning	Job set up	Upon approval	
Design	Contract preparation for CI and overhaul	Upon approval	
Procurement	Award of contract for CI and overhaul	October 2016	October 2016
Construction	CI and overhaul	November 2016	November 2016
Closeout	Project Closeout	December 2016	December 2016

Hydro recognizes that the schedule reflected above is aggressive. However, Hydro plans to complete this work and have the unit returned to service prior to December 1.

This work is being proposed as a supplement to the 2016 Capital Program to ensure that the unit is available and reliable for the 2016/17 winter operating season. Submitting this request as a part of the 2017 Capital Program would potentially result in this unit being unavailable for a part of the 2016/17 winter operating season.

APPENDIX A

Equivalent Starts Calculation

Calculation of Equivalent Starts

The effects of thermal stress caused by starts, trips, and load changes are cumulative and are monitored using equivalent starts. The following equation is used in the calculation of equivalent starts. A sample calculation is provided below to illustrate the use of the equation based on operating data.

$ES = \Sigma(S * Sf*Ff) + \Sigma(A*Ff) + \Sigma(T*Tf*Ff) + \Sigma(I * Lf*Ff)$

Where:

ES = Equivalent Start

S = Successful Start

A = Fired Abort

T = Trip from load

I = Instantaneous Load Change

Sf = Start Factor – normal start = 1; Fast start = 10

Tf = Trip Factor – based on load change % of base load

Lf = Load Change Factor – based on load change % of base load

Ff = Fuel Factor = 1.3 for distillate fuel

Definitions:

1. Fired Abort – A fired abort is a start attempt that aborts or is aborted after combustion ignition has occurred, but shuts down before reaching breaker closure.
2. Trip from load – A trip from load occurs if the unit is shutdown after breaker closure AND the normal shutdown full speed no load (FSNL) cool down sequence is not performed. This is a shutdown that does not follow the normal shut down sequence including but not limited to the specified FSNL cool down sequence.
3. Instantaneous Load Change – Instantaneous load change occurs when a unit abruptly increases or decreases load at a rate greater than the specified ramp rate.

<u>Sample Equivalent Starts Calculation</u>

Following is a example of an equivalent starts calculation for a period of operation in which the events listed below occurred.

10 successful starts – normal start

2 fired aborts

1 trip from load at 40MW

1 instantaneous load change from 80MW to full speed no load (FSNL)

ES = Σ(S * Sf*Ff) + Σ(A*Ff) + Σ(T*Tf*Ff) + Σ(I * Lf*Ff)

ES = (10*1.0*1.3) + (2*1.3) + (1*7.0*1.3) + (1*4.0*1.3)

= 13 + 2.6 + 9.1 + 5.2

= 29.9 ES

So, in a month where there were 10 actual starts, the unit would accumulate 29.9 equivalent starts based on the operating data used. A fuel factor of 1.3 is applied based on the use of diesel fuel.

Establishing a Robust Operational Philosophy and Enhancing Skills and Capabilities Relating to Systems Reliability and Analysis

March 30, 2017

A Report to the Board of Commissioners of Public Utilities

newfoundland labrador hydro
a nalcor energy company

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1.0 Introduction

On October 13, 2016, the Board of Commissioners of Public Utilities (the Board) requested Newfoundland and Labrador Hydro (Hydro) provide a report on the actions taken in response to each of Liberty's recommendations in its report dated October 22, 2015, on the March (2015) outage, including all actions and plans to establish a more robust operational philosophy regarding reliability and to enhance the skills and capabilities of Hydro's employees related to reliability engineering and analysis.

This report details the actions that Hydro has taken to establish a more robust operational philosophy and its plans to establish a more reliability-centric culture. This report also discusses the actions taken by Hydro to improve the skills and capabilities of its employees related to reliability engineering and analysis.

It must be recognized that changing an organization's culture takes time. It is a large-scale undertaking that requires the organization to first change its behaviours knowing that the mindset of its employees will follow. Hydro has implemented many changes since the outages in 2014 and more following March 2015 events. The company is more risk focused and strives to remove known risks in addition to mitigating and managing those it cannot fully remove. Today, Hydro's new leadership has set expectation that the approach to the overall system management is to be customer focused with a goal of continually improving reliability as well as transparency with our customers on system conditions. There is also an expectation of a heightened and urgent response to system events to ensure that any outages or customer impacts are minimized to the extent possible. This has been achieved by implementing a number of changes in practises and processes which are directly benefiting customers and fundamentally resetting the utility focus of Hydro.

Hydro has made significant progress since 2014 and has a fundamental strategy of renewing the focus of Hydro and its employees to its core business of supplying its customers with a safe and reliable power supply. Hydro has demonstrated to the Board and its customers improved operational philosophy and an increased focus on service continuity for the customer. Hydro also acknowledges that this work and the improvements to culture, processes, practices will continue with appropriate urgency, driven by the current leadership but supported across the company. Some examples of where Hydro's approach has ensured service continuity include:

- In 2016, Hydro experienced boiler tube issues at the Holyrood Thermal Generating Station (HTGS) and took deliberate actions to ensure minimal customer outages. The thermal generating units were run at lower loads and the gas turbines were started in advance to ensure service continuity. There was no visibility to cost recovery for the operation of the gas turbines; Hydro took this action solely to ensure reliability of the system for customers.
- Starting in 2016, Hydro leased a spare engine that provides redundancy for its gas turbines. Hydro believes that the need for reliability of the gas turbine generation warrants the additional leasing costs and will continue to lease the spare engine.
- In 2017, Hydro entered a long-term maintenance contract with Siemens for the Holyrood combustion turbine (CT). The Holyrood CT is an important component of the Avalon contingency reserves and securing a long-term service provider will improve access to parts inventories, improve service response times and contribute to the overall reliability of the grid.
- In 2017, Hydro experienced air flow issues with the generating units at HGTS that have caused de-ratings to each unit. Due to the importance of the HTGS to the Island Interconnected System (IIS) and Avalon Peninsula, and rather than leave both units de-rated until the summer maintenance season, Hydro is planning an outage in April to restore capacity to one unit as quickly as possible.
- The March 11, 2017, windstorm shows an improved operational philosophy for Hydro and demonstrates many of the improvements discussed in this report. The impending weather conditions (extreme wind; up to 180 km/hr) were recognized early and it was decided during the daily system status meeting that a storm preparation would be

required. During the storm preparation meeting, Hydro created a plan to respond to the impending weather event and it was decided that crews would be placed on standby in advance of the weather for quick mobilization to areas requiring attention. Once the storm hit and outages were experienced, Hydro staff was able to respond quickly, thus minimizing the outages. Internal communications kept all stakeholders informed of the status and progress of unplanned outages and Hydro was in direct communication with Newfoundland Power and the general public. Hydro staff reacted appropriately and quickly to minimize the impact of the storm, with engagement of all levels of the organization. Hydro's system was exposed to design specification wind loading and experienced damage that was not extensive during this event. Hydro is reporting to the Board separately on the March 11, 2017, windstorm.

The above are a few examples only. Each of the changes outlined in this document directly influences the organization's philosophy and culture, moving ever-further in its evolution as a reliability-focused organization. Hydro will continue to learn, grow and evolve its operational philosophy while continuing to improve service continuity.

2.0 Establishing a More Robust Operational Philosophy

2.1. Overview

Liberty recommended that "Hydro should assign a team to implement a program to establish a more robust operational philosophy regarding reliability."[1] Hydro regards service continuity as being critical to its customers and seeks to continually improve its service reliability. Reliability has been enhanced over the past several years through a series of strategic operational and system improvements undertaken by Hydro.

[1] The Liberty Consulting Group, "*Review of the Newfoundland and Labrador Hydro March 4, 2015 Voltage Collapse,*" October 22, 2015, at page 10. Available at: http://www.pub.nf.ca/applications/March4thPowerOutage/files/reports/Liberty-Report-Oct22-15.pdf

In response to its customers, the Board, and Liberty's recommendations, Hydro has taken a number of actions, as explained below, to secure a reliable power system and to support a more robust operational philosophy.

2.2. Corporate Reorganization

Changes to both the Nalcor and Hydro organizational structures have improved executive focus on the principal functions associated with the delivery of service. These changes position Hydro to operate as an autonomous business entity within the Nalcor group of companies focused solely on its mandate of delivering safe, reliable, least-cost power to industrial, utility and residential customers in Newfoundland and Labrador.

2.2.1 Strategic Organizational Transformation

Since the power outage events of 2014, Hydro has implemented organizational changes that have transformed the company and improved its focus on core power generation and transmission operations, but through the lens of its customers. In its response to Liberty's Phase I report in early February 2015, Hydro acknowledged that its executive structure, as it existed below the level of President and CEO, did not consolidate all principal functions associated with the delivery of a utility service under one single executive. [2]

Hydro noted that the arrangement under which two Hydro vice presidents reported to the CEO was implemented in 2013 as a transitional structure that would ensure the required focus on ongoing operations, while at the same time enabling the Company to give the required attention to the future integration of Muskrat Falls with existing electricity operations. Hydro indicated that it would not maintain this structure in its longer term steady state operating environment, and further indicated that the manner in which Hydro and Nalcor Energy (Nalcor) would be structured for longer term electricity operations was actively under review.

[2] This report dated December 14, 2014 outlined various conclusions and recommendations by Liberty Consulting, specific to Hydro, as part of the *Review of Supply Issues and Power Outages on the Island Interconnected System* conducted by the Board.

Hydro also acknowledged that the regulatory affairs function in a regulated utility is a critical function. In its response, Hydro indicated its intention to fully consider Liberty's recommendation as part of Hydro's determination of its long term structure for electricity operations.

In November 2015 the position of President for Hydro was created to be ultimately responsible and accountable for all aspects of Hydro operations. Following the appointment of a new President and CEO for Nalcor in May 2016, a number of further organizational changes were instituted. The direction provided by Nalcor's CEO as part of his overall reorganization of Nalcor was that Hydro was to be operationally independent from Nalcor and its other lines of business. The goal was to ensure organizational separation and simplicity for Hydro as it relates to operations management, budgeting and financial management, performance accountability, and regulatory oversight.

Organizational changes were made with the intention of creating clear separation between Hydro as Nalcor's established regulated utility. A new President for Hydro was appointed in June 2016. Following this appointment, Hydro reviewed its organizational structures and subordinate organizational structures for all areas of operations. Figure 1 presents the high level executive structure for Nalcor that was announced by Nalcor's President and CEO in June 2016.

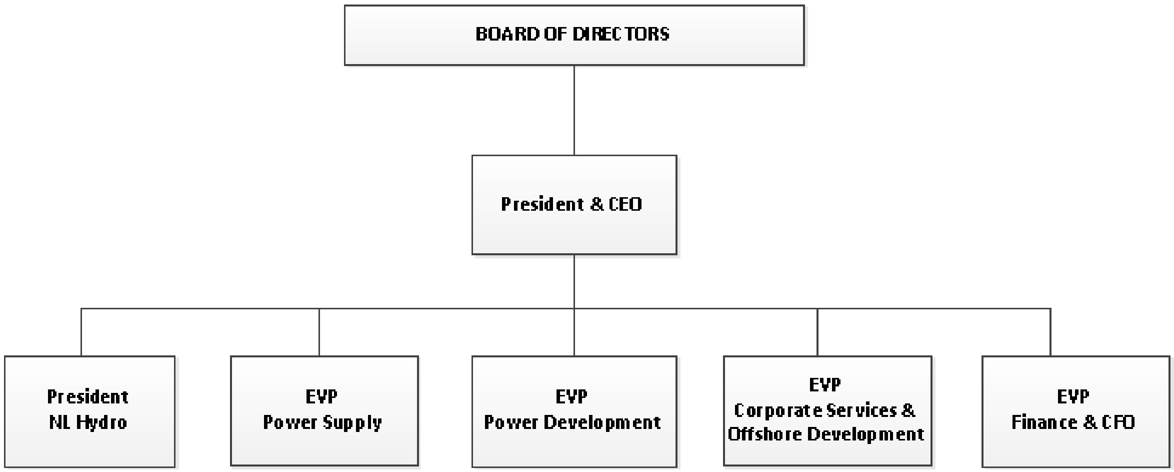


Figure 1: Executive Structure – Nalcor Energy

2.2.2 Hydro's Organizational Structure

Hydro's new executive structure reflects a more encompassing organizational model that ensures that core functions required to operate the company as an operationally independent, stand-alone organization have clear accountability within the new structure.

Hydro's new executive structure reflects a more encompassing organizational model that internalizes the core functions required to operate the company as an operationally independent, stand-alone organization. All functions have clear accountability within the new structure. The new divisions include:

- **Production –** The Production Division encompasses all aspects of power generation within Hydro, including hydroelectric, thermal, diesel, and gas turbine generation, as well as generation planning. Exploits Generation, which was previously managed as part of Hydro's non-regulated operations, is now managed by Production Operations, under its hydraulic generation group.
- **Transmission, Distribution, and NL System Operations –** The Transmission, Distribution, and NL System Operations Division also includes transmission planning and is

responsible for the transmission and distribution of power throughout the Island and Labrador. The incorporation of System Operations, transmission planning and the Energy Control Center optimizes the operation and planning of the core provincial power system.

- **Engineering Services –** The Engineering Services Division includes asset management, project execution and technical services employees. The division also includes an Information Systems and Operations Technology group that are focused on ensuring that Hydro's has the core systems required for the business as well as maintaining the company's Energy Management System, Network Services and other critical IT infrastructure utilized in the Energy Control Center.
- **Regulatory Affairs and Corporate Services –** The Regulatory Affairs and Corporate Services Division consolidates and strengthens Hydro's organizational focus on regulatory affairs, including a dedicated legal resource, and integrates Customer Service, Energy Efficiency, Safety, Health, Environment and Corporate Communications.
- **Financial Services –** The Financial Services Division provides financial oversight and support to Hydro in the areas of Commercial Management, Treasury, Tax, Risk, Insurance, Supply Chain, Administration, and other financial services.
- **Corporate Secretary and General Counsel –** The Corporate Secretary and General Counsel Division provides core legal oversight to the company as well as Board Secretarial functions.

Figure 2 presents the executive level structure for Hydro announced by the President of Hydro in September 2016.

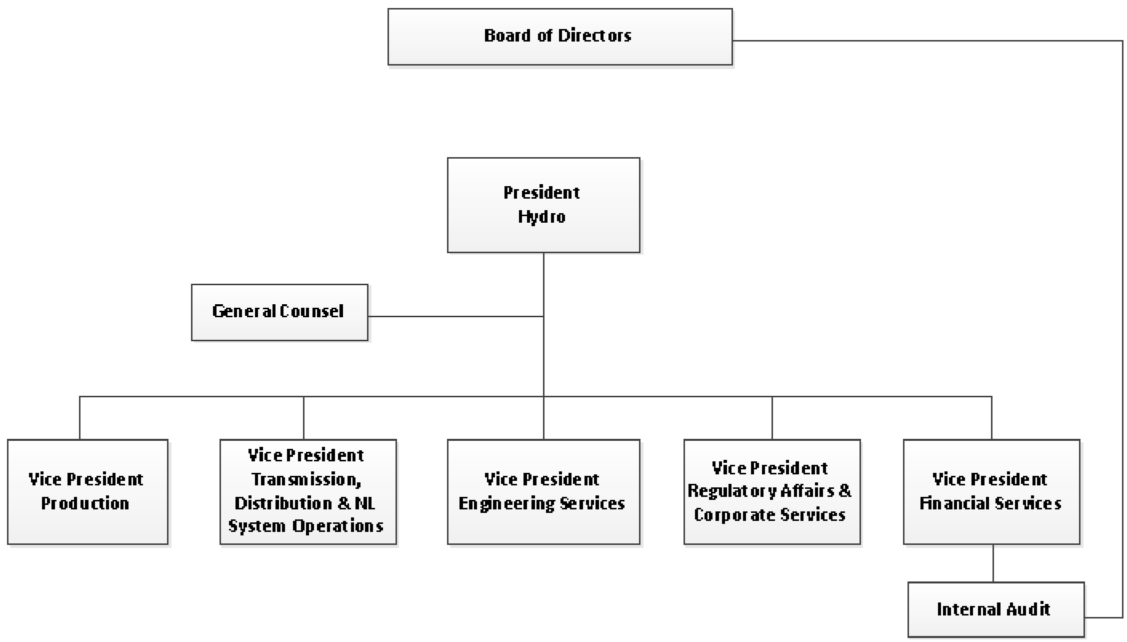


Figure 2: Executive Structure – Hydro

2.3. System Operations Improvements

Since the outages in 2014, Hydro's System Operations Department has made significant improvements that demonstrate meaningful change in its operational philosophy regarding system reliability. Hydro now takes a more holistic view of customers when assessing system conditions and is more focused on the end-consumer of its power, rather than being focused on the end-point of its power delivery.

This change in philosophy and practise has led to enhanced communications between System Operations and the rest of the organization through the addition of daily system status meetings, storm preparation meetings, and improvements in communication to Executive and Management to ensure awareness of both planned and unplanned outages. The Company has also increased its focus on the Avalon Peninsula supply, and has changed its approach for placing standby generating units into operation. Each of these improvements is described in detail in the following sections.

2.3.1 Daily System Status Meetings

Hydro's System Operations Department hosts a daily system status meeting where participants discuss power supply capability and reserves and other conditions that could impact the reliability of the Island Interconnected System and/or the Avalon Peninsula.

Traditionally, power system discussions were held internally within the System Operations Department and had an internal focus to the Energy Control Center (ECC). Stakeholders within Hydro were engaged with respect to any concerns related to their area's assets. This meeting has since evolved into a very structured process that includes key individuals throughout Hydro with primary responsibilities tied to the reliability of the Island Interconnected System, including participation from Hydro Executive and Management representatives from

Production, Transmission, Distribution, System Operations, Communications, and Regulatory Affairs.[3]

The increased scope and structure of the daily system status meeting has improved the reliability culture at Hydro by improving internal communications within Hydro as well as a broader system status understanding for a large group of people involved in various aspects of system management and monitoring. All stakeholders are engaged and aware of the various factors that might impact the power system. As part of these meetings, system reliability assessments, based on load forecasts for the current day and for the next seven days, are reviewed and discussed for both the Island Interconnected System and the Avalon Peninsula. These assessments outline the expected reserves based on the load forecast and the availability of assets which include primary generation, standby generation and in the case of the Avalon, transmission availability.

There is a review of weather warnings and special weather statements issued by environment Canada that can impact the Island Interconnected System. An additional storm preparation meeting is held if participants decide it is warranted (see Section 2.3.2). A review of the 14-day weather outlook is also reviewed. Hydro's internal load forecasting application (Nostradamus) generates a load forecast for seven days. The 14 day forecast outlines the expected temperatures beyond the seven day load forecast so there is a better understanding of potential high load days outside the immediate seven day window.

The previous day's power system events are also discussed to understand any outages or equipment issues. This activity gives participants a better understanding of the current state of

[3] The only days in 2016 that this meeting did not occur were Christmas Day and New Year's Day. It was determined on Christmas Eve and New Year's Eve, respectively, that the following days meeting was not required as the system and weather conditions indicated that there were no impending risks. All representatives remained on call for these days in the event of a system issue.

the power system and can serve as a lessons-learned activity for meeting participants. Existing and planned equipment outages are also reviewed to assess their impacts on short and long term and can lead to cancelling planned outages or implementing contingency plans if the load forecast warrants this action. After each meeting, summary notes are prepared and distributed to the meeting participants. An example of these meeting notes is located in Appendix B.

2.3.2 Storm Preparation Meetings

Storm preparation meetings are held when Environment Canada posts special weather warnings related to wind, rain, freezing rain, and/or snow that have the potential to negatively impact the Island Interconnected System. The decision to hold this meeting is at the discretion of System Operations and the Executive Team and depends on the scope and severity of the weather event. This practice began in January 2016 and these meetings provide a structured review of the current state of the system, the preparedness of each operational area, and ultimately improve system reliability by ensuring that each operational area is ready to respond quickly and effectively to any severe weather impacts.[4]

The meeting includes a review of the weather warnings and the areas of concern. Representatives from the impacted area will review their severe weather checklists, referenced in Appendix C, to confirm they are prepared to address storm impacts. Equipment and generation capacity is also reviewed so that system risks can be identified and subsequently accounted for in system preparation action plans. If the weather event is considered severe, Hydro may proactively staff terminal stations and generation sites to reduce travel time, help troubleshoot any issues, and ultimately respond faster to incidents and reduce outage durations.

[4] If the meeting is warranted, System Operations will notify each operational area. The operational areas of the organization all have severe weather checklists that will be completed and forwarded to System Operations in advance of the meeting. The storm preparation meeting includes the same invitees as daily system status meeting.

For example, it was determined during the daily system status meeting that a storm preparation meeting would be required for the windstorm that was forecasted for March 11, 2017. During the storm preparation meeting, Hydro reviewed the weather warning, its impact on each region, and then created a plan to respond to the storm. It was also decided that crews would be placed on standby for quick response to where the issues were experienced.

2.3.3 Improved Internal Outage Communication

Hydro has improved its internal communications during maintenance activities for both planned and unplanned outages. If an outage is time sensitive, for example a unit trips off line, then the asset owner proactively communicates during the outage to Executive and Management.[5]

This communication includes updates on work progress, expected return to service of equipment, and other details that are important for the safe and reliable return to operation. These updates ensure timely information is communicated to all internal stakeholders and allows for proactive management and additional actions, when necessary, including external updates to customers and other stakeholders.

As an example, Hydro has set clear expectations for how the Holyrood Control Room communicates with the Energy Control Center during times when a unit is down for a planned outage. If the unit is going to be delayed, they are to inform the ECC and the ECC will notify the system on call[6] and System Operations personnel. The system on call will notify the Hydro Executive Team. This is required as a review of both the Island Interconnected System and

[5] Includes representatives from the various functional areas, including Production, Transmission, Distribution, System Operations, Communications and Regulatory Affairs as included in the daily system status meeting.

[6] The system on call is the on call person that is responsible for issues related to the entire power system. The individual is intended to be the communication liaison for large scale system wide issues which require more analysis (i.e. reserves levels) or to coordinate support. It can also be used for technical advice as required.

Avalon reserves would need to be completed to ensure reserve levels will be maintained and if there are any requirements for alert level notification.

2.3.4 Increased focus on the Avalon Peninsula Reserves

Over fifty percent (50%) of the customer load is located on the Avalon Peninsula and System Operations has a requirement to safeguard against the worst case contingency on the transmission system into the Avalon Peninsula. To this end, system operating instruction "Avalon Capability and Reserves (T-096)" (see Appendix D) was created to provide a method of assessing capability and reserves specific to the Avalon Peninsula. This instruction was approved internally at Hydro on June 26, 2015, and submitted to the Board for information on October 14, 2015.

Since April 8, 2015, system reliability assessments for the Avalon Peninsula have been performed daily, based on current load forecasts for the next seven days. These assessments determine the reserves for the Avalon Peninsula for the next seven days given the availability of the assets, which includes primary generation, standby generation, and sources of reactive support, such as capacitor banks.

T-096 provides clear instruction to operators that reserves equal to the single largest contingency, plus an additional reserve of 35 MW must be maintained for the Avalon Peninsula. If the reserves are expected to go below this contingency factor, then the policy provides clear instructions of the steps required to restore the appropriate reserves.

In addition, System Operations will monitor Avalon contingency reserves in real-time. This takes into account transmission line capability and generation asset capabilities. This real-time analysis allows operations to monitor the Avalon reserves and make decisions to maintain these reserves, as per operating instruction T-096.

For example, on March 27, 2017, based on the load flow analysis,[7] a Power Watch was issued for the Avalon Peninsula and no warning was issued for the Island Interconnected System. There has not been any power alerts issued for the Island Interconnected System since 2014. All of the alerts issued have been related to the Avalon.

It is important to note that when level 2 (Power Watch) situations are experienced, Hydro analyzes the reserves more frequently and updates interested parties, often having more frequent system calls than the daily norm. Depending on the time of the issue, 6 am and 9 pm calls may be held to ensure the right people are informed and ready to respond. While being highlighted as part of the analysis of reserves, this is a significant situational awareness and communication improvement illustrating the behavioural and cultural shift within the organization.

2.3.5 Island Spinning Reserves

Spinning reserve is the extra generating capacity that is available by increasing the power output of either hydro or thermal generators that are already connected to the power system.

Operators use operating instructions to operate the power system in an efficient manner. Operating instructions look at system-wide impact. The operating instruction "[IIS] Generation Reserves (T-001)" (see Appendix E) determines the amount of spinning reserves to maintain on the Island Interconnected System. T-001 provides direction to the Energy Control Center to take appropriate action to maintain a minimum spinning reserve level equal to 70 MW. This operating instruction applies to the entire Island Interconnected System. Maintaining appropriate spinning reserves covers performance uncertainties in generating units, especially wind and other variable generation and unanticipated increases in demand. It can also allow for quicker restoration times on outages. As an example, if a generator trips, it could cause an

[7]**Load flow analysis** is used to determine if system voltages will remain within specified limits under normal and emergency operating conditions, and whether equipment is overloaded during these conditions.

under frequency load shed event with loss of customers. The ECC can quickly request to restore customers using the online spinning reserve. In this example, the ECC will also make calls to senior management and on-call personnel to ensure that all stakeholders are aware of the situation.

2.3.6 Operation of Standby Units

In its process of improving system reliability, Hydro has started to operate standby generation in advance to cover generation or transmission outages equal to the worst case contingency (for either Island or Avalon) and to maintain Island spinning reserves. Based on reserve requirements, the Energy Control Center will operate the Hardwoods gas turbine, Holyrood combustion turbine, and Holyrood diesel standby generating units (or a combination thereof) in advance of the single largest Avalon contingency, rather than starting them after the event has occurred. This maintains the Avalon reserve. This practice results in lower risk of customer impact and unserved energy in the event of a contingency.[8]

For the Island, standby generation is started in advance to maintain appropriate spinning reserves. In addition to the standby generation mentioned previously, the ECC will operate the Stephenville gas turbine and the Hawkes Bay and St. Anthony diesel generators for Island spinning reserves.

To support this improvement, Hydro's ECC operators now receive daily standby generation requirements from System Operations, supporting both the Island Interconnected System and the Avalon Peninsula transmission, which allows operators to understand predicted changes to the load forecast and better plan for system continuity. The standby generation requirements are sent each morning as part of the daily system status meeting notes to the daily system status meeting participants. There is also a standby generation group email created that

[8] An example of a contingency would be the loss of a major 230 kV transmission line that supplies the Avalon with power generated off of the Avalon. The contingency may occur in the future and therefore must be prepared for. http://www.nerc.com/files/concepts_v1.0.2.pdf

receives these notifications. The requirements are monitored throughout the day and if there are any changes due to load forecast changes, System Operations will send a revised standby requirement.

2.4. Integrated Annual Work Plan (IAWP)

The Operations and Engineering divisions within Hydro prepare an annual work plan (AWP) to schedule and plan maintenance activities critical to providing customers with safe, reliable electricity. These activities include capital projects, preventative maintenance, corrective maintenance, non-maintenance, and operating project work. Once finalized, these plans form the baseline for each division's work plan for the year.

Traditionally, each division prepared their plan in the first quarter of the year and then executed that plan throughout the year, mostly in isolation from other regions. When outages were required for work in that region, the regions would deal directly with System Operations, who would then coordinate any conflicting work being scheduled across the regions.

Since 2014, Hydro has taken a more holistic approach to the work planning function and now creates an integrated annual work plan (IAWP) that includes all capital and maintenance work plans for all regions. The IAWP allows planners to get a full view of the annual resource requirements, including peaks and valleys. The planners can then reschedule work so that the peaks are reduced and valleys levelled, leaving the organization with a more realistic and balanced work plan for the year. Any peaks that exist after this process are reviewed again and external contractors are then engaged for critical pieces of work. This integration of work plans has improved the coordination of equipment outages and improved communications between Operations and Engineering Services.

Many of the maintenance items included in the IAWP are outage dependent and System Operations have the final decision for planned outages. System Operations are engaged early in the planning process and review with a holistic view of all required outages which allows them to proactively detect any conflicts in the IAWP that would not be acceptable for system continuity. System Operations will then adjust the outage schedule and eliminate conflicts to maintain the integrity of the system. The IAWP is subsequently adjusted, thus improving accuracy of scheduled equipment outages.

These integrated work planning processes have improved intra-company communications and accuracy of the IAWP. The integrated annual work plan has become a core process for work, outage and resource planning and has a direct impact on customer reliability.

2.4.1 Winter Readiness Plan

The winter period is a critical time period for Hydro. Newfoundland and Labrador winters exhibit significant variability in temperature and other weather conditions. Winter will bring below freezing temperatures, snowfall, freezing rain, high winds and other extreme weather conditions, such as blizzards. Hydro recognizes that power system reliability over these months requires assets to be in peak condition so that they can perform optimally in these extreme conditions.

The Winter Readiness Plan is a subset of the IAWP and was created to ensure system reliability during the winter months. It includes those preventative maintenance, corrective maintenance, and capital project work items that are considered necessary to ensure that Hydro has the generation, transmission, and distribution equipment ready for the upcoming winter season. The deadline for completing these items is December 1 of each year and Hydro reports its progress of winter readiness items to the Board on September 30, October 30, and November 30 for the upcoming winter season.

The creation of the Winter Readiness Plan helps Hydro set priorities and create work plans that focus on being ready for the upcoming winter season. If it is anticipated that winter readiness items will not be completed by November 30, Hydro completes a risk assessment of each item and a recovery plan to complete the necessary work, or develops risk mitigation strategies, as required.

2.4.2 Maintenance Tracking Report

Hydro regularly measures and tracks its progress towards the completion of its IAWP, down to the level of individual work plan items. Traditionally, regions tracked the progress of their individual work plans using traditional project management software. In March 2016, following the completion of the baseline IAWP, a maintenance tracking system was implemented using Hydro's enterprise project portfolio management software. The tracking system includes the annual work plans for each division that collectively create the IAWP.

The planners within each division track progress towards completion of their work plan and progress is then reported bi-weekly in the maintenance tracking report. The report shows progress within each division and then for Hydro as a whole. As maintenance progresses and plans need to be adjusted, the planners within each division adjust their original plans. These adjustments may include the removal of non-critical activities, the addition of activities, or rescheduling of activities. The Maintenance Tracking Report tracks these adjustments.

This report is delivered to Hydro Management bi-weekly and improves management's visibility to IAWP progress. If issues have been encountered, management are made aware promptly, thus giving them time to enact mitigation strategies and host risk-based discussions for any items not completed or that are impacted by changes.

Hydro has also developed an outage tracker with a look ahead on equipment outage readiness. This provides visibility on factors that can affect upcoming maintenance or capital work, such as permitting or resource availability. Any areas that may prove a risk to readiness are flagged and addressed in advance of outages to ensure the plan can proceed (see section 2.5).

2.5 Equipment Outage Management Tracker

In February 2016, Hydro implemented an Equipment Outage Management Tracker, displayed in Appendix F, to minimize impact on customers, improve the efficiency of work planning, manage the duration of planned outages, and improve overall system reliability. The outage management tracker was reviewed twice weekly at the daily system status meeting leading up to and during maintenance and construction season and was reviewed more frequently by the regions completing the work. It is a risk management tool that is linked to the IAWP and captures all upcoming planned outages for generation, transmission and stations. The outage tracker has become an essential tool for Operations in ensuring that planned outage durations are minimized and do not introduce an unacceptable level of risk to customers on the Island Interconnected System.

Each planned outage can require a number of mandatory permits, involve a number of internal and external stakeholders, and consist of various levels of complexity. The outage tracker formally documents requirements that are critical to the outage and ensures their preparedness before any outage will proceed, thus ensuring outage time is minimized to just the essential tasks. The tracker ensures work is ready to proceed.

The Planned Outage Database gives the Energy Control Center a single-view of all upcoming planned outages. This single-view allows the operators to review all of the planned outages for that day and make a reliability assessment. If too much risk is introduced to the power system by the planned outages due to system conditions (i.e. other equipment out of service, weather, etc.) then an outage will not proceed and modifications to the planned outage schedule will be required to reduce the level of risk. The outage tracker provides a status update for each planned outage and all items must be checked in the outage tracker before being approved in the Planned Outage Database. This updated status in the Outage Management Tracker is used in conjunction with the Planned Outage Database to give the ECC and Operations a clear picture of the upcoming planned outage requests, and a better line of sight for managing system risks.

2.6 Reintroduction of Hot Line Work

Hot line work, also referred to as live-line work, refers to the maintenance and upgrade of electrical equipment, often at high voltage, while the equipment is still energized. Hot line work techniques can be used in a variety of maintenance activities, including changing and testing of insulators, replacing damaged sections of conductors, replacing transmission poles, and other maintenance activities.

Performing maintenance on energized electrical equipment can be dangerous as one mistake can result in fatalities. As a result, hot line work requires line crews to be trained in live-line work techniques and use specialized equipment and procedures that prevent potentially hazardous voltage differences across the worker's body. Hydro stopped utilizing live-line techniques after two incidents resulting in fatalities occurred during the maintenance of energized equipment. At the time, there were concerns of further incidents so system outages became the preferred method for performing maintenance activities.

Safety standards and specialized training exist that together allow live-line work to be completed safely. There are many advantages to utilizing hot line work techniques. It allows a utility to complete maintenance activities with fewer planned outages, thus maintaining continuity of service for customers, and provides greater flexibility for maintenance activities, allowing for efficiency of operations. Overall, hot line maintenance techniques improve system reliability and stability for customers.

Recognizing the advantages that hot line techniques deliver, Hydro has begun to reintroduce this maintenance approach and now utilizes contractors trained in hot line work techniques to perform live-line maintenance activities. In 2016, Hydro utilized hot line work to repair a damaged splice on one of its Avalon Peninsula 230 kV transmission lines and to also replace insulators on the Bottom Waters system. Both the 230 kV transmission line and Bottom Waters work were critical to providing reliable power and Hydro was able to complete necessary maintenance to ensure the integrity of the system, while avoiding any disruption of power to customers.

Hydro is currently finalizing recommendations to further introduce and utilize hot line techniques to both transmission and distribution work activities over the coming years.

3.0 Improving Reliability Engineering and Analysis Skills and Capabilities

Liberty recommended that "Hydro should enhance the skills and capabilities it brings to reliability engineering and analysis."[9] Hydro is committed to the development of its personnel and will continue to look for opportunities to improve staff's training and knowledge in the fields of reliability engineering and analysis.

As detailed throughout this report, Hydro has enhanced its reliability foundation over the past number of years and increased medium to long term capital investment planning. As outlined in Section 2.3.4 of this report, Hydro has introduced capacity assessment criteria for the Avalon Peninsula that are used to make decisions from both an operational and communications perspective.

The sections below outline other actions that have provided improvements in these areas.

3.1 Energy Control Center Operator Training

Hydro recognizes the importance that ECC operator training has in regards to improving its skills and capabilities of ECC operators for system reliability.

Hydro has an Operating Training Simulator (OTS) training facility for the Energy Control Center operators. Previously, the training space was a shared space with the Corporate Emergency

[9] The Liberty Consulting Group, "*Review of the Newfoundland and Labrador Hydro March 4, 2015 Voltage Collapse,*" October 22, 2015, at page 10.

Operations Center (CEOC) and consisted of one trainee console and a console for the trainer. In 2016, Hydro created a dedicated OTS Training Facility for operators. This facility includes training consoles for operators, a separate console for the trainer, and has its own training digital video wall display. It can simultaneously train up to 3 operators.

The Operator Training Simulator is used to train the system operators in both normal and emergency operation of the power system. Scenarios are developed which simulate various generation and load configurations. The OTS simulates real-time operation, allowing system operators to see the impact of contingencies, learn how to respond to events, and complete restorations.

OTS training is scheduled three times each year. Many different scenarios have been developed to simulate contingencies on the Interconnected Island System, including scenarios on the Avalon Peninsula. These scenarios have components of monitoring power system elements such as acceptable voltage levels, transmission line loadings, and frequency. As the system operators go through the simulation of restoration, they learn how load restoration impacts system voltages. The system operators must maintain these voltages within acceptable levels. As well, there are system operating instructions that are relevant to these scenarios that are used as part of the training. These instructions are procedures for restoration and maintaining acceptable operating criteria. In essence, the OTS training also keeps the system operators up to date on these operating instructions.

System operators have also been given training in alarm monitoring and management. This was completed as part of an OTS training session and was developed to ensure the system operators identify critical terminal station alarms and understand the appropriate response to the alarm. Essentially, before restoration can commence, if there are alarms at the station, a discussion with the asset owner needs to take place. The alarms would need to be cleared or permission given to the Energy Control Center to proceed depending on the nature of the alarm.

System Operations uses the OTS to continually improve the knowledge of operators. The simulator can be programmed with different contingencies based on real world learnings. For example, an OTS session was also developed that simulates the events of March 4, 2015. All of Hydro's Energy Control Center operators participated in this simulator training session, where they experienced declining voltages on the Avalon power system and acted accordingly to stabilize and restore the system.

The new training facility will be critical to System Operations as the Maritime Link (ML) and Labrador Island Link (LIL) are commissioned and operators are trained to manage these new assets and interconnectivity with the North American power grid.

3.2 Corporate Reorganization of System Operations

Hydro has completed organizational changes that demonstrate the importance of a structured and focused system operation's function. Some of the changes are being made to support the creation of the Newfoundland Labrador System Operator (NLSO) and other changes are part of continuous improvement initiatives. Section 7.1 provides an overview of the changes being made in advance of the creation of the NLSO. This section outlines current organizational changes that have added to the department's capabilities, and the removal of peripheral tasks has increased staff's focus on their primary responsibilities, ultimately leading to improved system reliability.

The Transmission Planning Department has been integrated with the System Operations Department. Collocated in the same office space, the transmission planning and system operation's staff are now able to work closer together. This change has helped to improve communications and cohesion between operations and transmission planning.

To improve focus on primary functions, the tasks of industrial customer billing and invoicing and meter validation have moved to Customer Service. Water management has been moved from System Operations to Production (December 2016) and fuel/power purchase forecasting and budgeting is currently being transitioned to Production. The requirement for System Operations to report on asset failures has now been transitioned to Regulatory Affairs. Asset owners now send their outage reports to Regulatory Affairs, who subsequently send to the Board. System Operations are no longer tasked with submitting outage reports on behalf of the organization.

Traditionally, the industrial customer relationships were managed inside System Operations. In 2016, Hydro created a Manager, Key Accounts position within Customer Service that is now accountable for the overall relationship between Hydro and its key industrial and general service customers across the Province. This Manager is the single point of contact for all services and communications provided by Hydro to its industrial customers and leads the resolution of electricity-related issues impacting key customers. This allows the Energy Control Centre Operators and System Operations to focus on the power system. For the customer, the Manager, Key Accounts has a much deeper understanding of the customers' business operations and can advocate on their behalf when planned outages and other pertinent matters are being discussed. The Manager, Key Accounts is the single point of contact for their interactions with Hydro and keeps industrial customers informed of planned outages, meets with them on a regular basis to understand their short-term and long-term needs, and navigates the internal Hydro organization for resolution to their questions, issues, and concerns. Understanding a customer's long-term plans allows Hydro to be more proactive and adjust its capital plans, if it is foreseen that improvements and/or enhancements will be necessary to meet customer requirements.

Hydro has also improved it after hours support for customers. Previously, the Energy Control Center was tasked with answering customer inquiries during planned and unplanned outages.

This was distracting and prevented the Energy Control Centre from focusing on issue resolution and power system management. A third party vendor was engaged to provide first-line response to customer inquiries for both planned and unplanned power interruptions that occur after business hours. The vendor was trained in Hydro's processes for dealing with power interruption inquiries and can engage on-call staff as required to follow-up with customers on resolution of issues after business hours. This change in process has been well received by both customers and staff.

All of these changes allow System Operations to focus their efforts on the primary goal of maintaining a stable and reliable Island Interconnected System. This focused structure also allows the System Operations staff to plan for the integration of new assets that will be introduced as part of the Muskrat Falls Project and plan for the creation of the NLSO.

3.3 Supply Planning and Risk Assessment

In 2016, in an effort to improve its transparency, Hydro conducted a comprehensive energy supply risk assessment of its ability to meet Island Interconnected System energy and demand requirements until the expected interconnection with the North American grid.

The Energy Supply Risk Assessment is an in-depth review of all of Hydro's assets and includes load forecast analysis methodology for assessing Hydro's ability to meet the demands of the Island Interconnected System and the Avalon Peninsula major load center. This assessment represents a significant milestone in Hydro's evolution towards improving its system planning techniques and reliability engineering.

The purpose of the Energy Supply Risk Assessment is to:

- Analyse the reliability of Hydro's existing generation assets, including: a) the thermal generation assets at the Holyrood Thermal Generating Station, b) the gas turbines at Hardwoods and Stephenville, and c) Hydro's hydraulic generating facilities;

- Determine Hydro's ability to meet its demand requirements given the projected reliability of these assets;
- Determine expected reliability for these assets through to the interconnection period;
- Analyse and determine Hydro's ability to meet its energy requirements for a range of unit reliabilities in consideration of the historical dry sequence;
- Consider alternative load growth scenarios and Hydro's ability to meet the associated change in forecast demand; and
- Provide alternatives and options to mitigate exposure, if required.

Hydro filed its energy supply risk assessment with the Board on May 27, 2016,[10] and submitted an updated copy of the report on November 30, 2016.[11]

This review provided Hydro staff with focus on the critical asset components that must be addressed within the IWAP. Hydro's asset reliability is a critical component in determining its ability to meet its generation and transmission planning and load forecasting criteria.

Based on the findings of the November 2016 energy risk assessment, Hydro is confident in its ability to meet Island Interconnected System requirements from an energy and capacity perspective. Hydro also concluded that until interconnection to the North American grid is achieved, for the sensitivity cases only, there is some risk of minimal unserved energy in excess of planning criteria for the current winter of 2016-17. [12]

[10] Newfoundland and Labrador Hydro, "*Energy Supply Risk Assessment –May 2016.*" Available at: http://pub.nl.ca/applications/IslandInterconnectedSystem/phasetwo/files/reports/From%20NLH%20-%202015-2019%20Energy%20Supply%20Risk%20Assessment%20-%202016-05-27.PDF
[11] Newfoundland and Labrador Hydro, "*Energy Supply Risk Assessment –November 2016.*" Available at: http://pub.nl.ca/applications/IslandInterconnectedSystem/phasetwo/files/reports/From%20NLH%20-%20Energy%20Supply%20Risk%20Assessment%20Report%20-%20UPDATED%20November%202016%20-%20Revision%201%20-%202017-01-26.PDF
[12] In one case, the load that is forecast to decline actually stays stable, and in the other case, the industrial load is assumed to increase compared to forecast.

The following sections outline the methodology and planning criteria used to make this determination and the strategies that Hydro is using to mitigate this risk. An updated Energy Supply Risk Assessment will be submitted to the Board in May 2017 that includes updated system demand forecast, updates to new asset deliverables, and other changes based on Hydro's assessment of current system realities. Hydro will also review Liberty's assessment of the November 30, 2016, Energy Supply Risk Assessment and make updates or additions where appropriate.

3.3.1 Demand Forecast Analysis

Hydro bases its generation supply planning decisions for the Island Interconnected System on a P90[13] peak demand forecast.[14] The P90 peak demand forecast reflects the associated increase in demand over the normalized (P50) peak demand forecast resulting from instances of severe wind and temperature. The development of the P90 peak demand forecast is an extension of Hydro's regularly prepared system operating load forecast and allows Hydro to assess its ability to reliably supply customers in instances of extreme weather conditions.

Hydro prepares its initial demand forecast in the spring of each year subsequent to receiving Newfoundland Power's load forecast update and the available industrial customer demand forecast updates. Hydro will subsequently revise its demand forecast in the fall, taking account of industrial customer's power requirement plans which are set in the fall for the following year and allowing for any revisions to Newfoundland Power's demand requirements. These demand forecasts are then used in the creation of the yearly Energy Supply Risk Assessment.

[13] A P90 forecast is one in which the actual peak demand is expected to be below the forecast number 90% of the time and above 10% of the time.
[14] In accordance with direction in the Board's letter to Hydro regarding Investigation and Hearing into Supply Issues and Power Outages on the Island Interconnected System - "Directions further to the Board's Phase One Report", received October 13, 2016.

As part of the 2016 Energy Supply Risk Assessment, Hydro updated its peak demand forecasts to reflect the latest available customer and system information available. The revised forecast was then used to review reliability of generation assets.

Hydro studied its demand forecasts with two planning criteria including:

a) An Expected Case,[15] and
b) A Fully Stressed Case for three different demand forecast projections,[16] including:
    1) Sensitivity Load Projection I (the stable utility demand case), [17]
    2) Sensitivity Load Projection II (the high industrial coincidence), [18] and
    3) Sensitivity Load Projection III (the high utility coincidence). [19]

Based on the projected asset reliability and demand forecasts listed in the November 2016 Energy Supply Risk Assessment, neither the Expected Case nor the Fully Stressed Reference Case result in Expected Unserved Energy (EUE)[20] in excess of planning criteria beyond the current winter of 2016-17 for either of the three sensitivity load projections. Both Sensitivity Load Projection II (the high industrial coincidence) and Sensitivity Load Projection III (the high utility coincidence) estimated a demand forecast result in EUE in excess of planning criteria for the winter 2016-17, only. This EUE in excess of planning criteria is observed for these cases despite having a relatively low increase in demand forecast for winter 2016-17 over the base case forecast, 9 MW and 12 MW, respectively.

[15] The Expected Case reflects Hydro's anticipated system capability and the P90 demand forecast with scheduled in-service of the Labrador Island Link and Maritime Link.
[16] The Fully Stressed Reference Case is a conservative analysis reflecting Hydro's anticipated capacity in consideration of the P90 peak demand forecast should no interconnection to the North American grid be established through winter 2019-20.
[17] Sensitivity Load Projection I - Stable utility demand: Assumes that in spite of the current forecast, which is for reduced energy requirements relative to 2015, demand requirements remain stable (i.e. lower load factor).
[18] Sensitivity Load Projection II - High industrial coincidence: Includes increased industrial load requirement over Hydro's base case expectation assuming less diversity in industrial customer demand requirements at island Interconnected system peak.
[19] Sensitivity Load Projection III - High utility coincidence: Includes increased utility load requirement over Hydro's base case expectation assuming less diversity in utility customer demand requirements at Island Interconnected system peak.
[20] Expected Unserved Energy (EUE) is the summation of the expected number of MWh of load that will not be served in a given year as a result of demand exceeding available capacity.

To mitigate this risk, Hydro has undertaken initiatives to secure additional curtailable Avalon Peninsula load to reduce the identified transmission exposure (see Section 3.3.3) and has accelerated the in-service of the third 230 kV transmission line from Bay d'Espoir to the Avalon Peninsula (TL267). The in-service of TL267 for winter 2017-18 more than mitigates any additional exposure for EUE in excess of planning criteria (see Section 3.3.2).

3.3.2 Accelerated Construction of Transmission Line TL267

On April 30, 2014, Hydro filed an application for approval to construct a 230 kV transmission line between Bay d 'Espoir Hydroelectric Generation Station and Western Avalon Terminal Station at Chapel Arm, including upgrades at both stations to accommodate the new infrastructure.

The transmission line project, now known as TL267, will increase Hydro's capability to deliver power to the major load centre on the Avalon Peninsula and will ensure the continued stability and reliability of the Island Interconnected System, particularly during faulting events. TL267 will help Hydro meet the long-term power requirements of the Island Interconnected System by providing additional capacity, enhancing resiliency to system faults, and relieving congestion on the existing transmission system.

Accelerating the in-service date of TL267 to October 31, 2017, will increase Hydro's capability to deliver power to the major load centre on the Avalon Peninsula and transmission constraints on the Avalon Peninsula will be eliminated to the extent that the loss of two Holyrood units will not result in transmission system violations.

As requested by the Board on July 19, 2016, Hydro has been filing monthly reports since September 15, 2016, that provides a status of this project. As stated in the March 12, 2017, report, the construction of TL267 is on schedule and Hydro is working aggressively to deliver this project on schedule for the 2017-2018 winter season.

3.3.3 Capacity Assistance Agreements

Capacity assistance agreements with industrial customers are used by many utilities as a way to reduce peak load by having large customers interrupt their operations. Hydro's capacity assistance arrangements are considered an appropriate utility practice and have been negotiated as an instrument of insurance for system reliability. The capacity assistance agreements allow for the purchase or curtailment of power from industrial customers.[21] For multiple reasons, demand can exceed Hydro's capability to generate and/or distribute the required power to meet the need. Usually there is a hierarchy of customers, in which some may be required to partially or totally reduce their power consumption. Industrial users, for example, are usually curtailed before service to residential users is reduced.

Hydro presently has capacity assistance agreements in place with the following industrial customers:

- 60 MW of capacity assistance from Corner Brook Pulp and Paper Limited (CBPP), as per Board Order P.U. 49(2014). CBPP interrupts its production activities to provide this capacity assistance to Hydro.
- 30 MW of capacity assistance from CBPP through a further interruption of mill operations, via the Supplemental Capacity Assistance Agreement.
- 7.6 MW of capacity assistance from Vale Newfoundland & Labrador Limited (Vale) to be provided to the Island Interconnected System from Vale's standby diesel generating facilities.[22]
- In December 2016, a 5 MW interruptible agreement was reached with Praxair Canada Inc. (Praxair), as per Board Order P.U. 55(2016).
- In January 2017, as per Board Order P.U. 3(2017), a 6 MW interruptible agreement was reached with Vale.

[21] Curtailment is the reduction of power delivery to a customer due to a shortage of supply.
[22] The agreement allows for up to 15.8MW of capacity assistance, with a test of Vale's diesel generating facilities each year. The test completed in 2016 confirms 7.6MW of capacity assistance for winter 2016-2017.

Hydro can also request Newfoundland Power to utilize its Curtailable Service Option to reduce its load requirements. The amount of curtailable load that is forecasted to be available for winter 2016-2017 by Newfoundland Power is 11 MW.

These capacity assistance agreements help to maintain generation reserves on both the Island Interconnected System and Avalon Peninsula systems and, in the case of significant system events, help to lessen the impact on residential customers. These agreements proved to be prudent actions, as capacity assistance requests were issued during the winter of 2014-2015, winter of 2015-2016, and winter of 2016-2017. These agreements have provided Hydro with operational flexibility during times of higher demand and/or unforeseen system events and were a core element in the company's pursuit of increased reliability and system continuity.

3.4 Equipment Failure Review Enhancements

Hydro has improved its new model for investigating equipment failures. Traditionally, individuals from the immediate operational area worked to primarily fix the issue and subsequently look for the root cause of the equipment failures.

In the new model, a broader focus to find the root cause of equipment failure is mandatory and frequently involves internal experts from across the organization, addressing issues with increased urgency. Lessons learned from previous equipment failures are also captured and incorporated into the current investigation so that insights learned during previous equipment investigations can be applied to the current review.

The investigation of the unit trip issue at Paradise River is one such example of the improved and more inclusive equipment review model. Paradise River is a hydroelectric generating plant that generates 8 MW of electrical power. The plant had been experiencing an increasing number of unit trips through 2016 in comparison to previous years. From January to mid-November 2016, the plant experienced almost 30 unit trips, compared to 4 in 2014 and 11 in

2015. No cause could be determined for a high proportion of the trips in 2016, despite a thorough review and inspection by staff at the plant.

Hydro expanded the review team, incorporating expertise from across the organization, to complete a more extensive review to determine the cause of the repeated trips.[23] The cross-departmental team developed a set of actions to structure the investigation. Following the cross-departmental investigation plan led Hydro to work with Newfoundland Power to replace a recloser[24] in their Monkstown substation. Since the installation, there have been no trips of the plant with an undetermined cause. This is a significant improvement over the frequency experienced prior to replacement.

This model is now being rolled out across the organization with the mandate of more consistent investigation and reporting, ultimately improving equipment reliability.

3.5 Membership in the Center for Energy Advancement through Technological Innovation

Hydro joined the Centre for Energy Advancement through Technological Innovation's (CEATI's) Power System Planning & Operations program to gain access to additional technical expertise and support Hydro's broad-based focus on system reliability.

The CEATI Program Model provides electrical utilities with a cost-effective vehicle for sharing experiences and addressing issues pertinent to their day-to-day operations, maintenance, and planning. The Power System Planning & Operations program's areas of focus include: a) planning and operations practices, including high-voltage direct current planning solutions, b)

[23] It has been hypothesized that the distribution line into which the plant is connected may be experiencing some system disturbances. Paradise River plant is connected to the Island Interconnected System via a distribution line, as opposed to a dedicated transmission line.

[24] A recloser is a protection device for electrical distribution networks. It combines a circuit breaker that trips if an overcurrent is detected with an electronically-controlled reclosing function that automatically restores power to the affected line if the fault clears itself quickly.

methods for increasing capacity and security, and c) modern simulation and modelling tools and techniques. The strategic direction of Power System Planning & Operations program is "…to enable the use of new technologies, including FACTS[25], to enhance the use of existing and new transmission facilities while continuing to maintain a high level of reliability. This includes exploring and developing tools and techniques for planning and operating transmission systems in a reliable, secure and cost-effective manner."[26]

4.0 Improving Situational Awareness

Liberty recommends that "Hydro should take steps to assurance situational awareness among operators and others who need the information to respond promptly and ably to adverse system conditions."[27] Situational analysis refers to the methods that staff utilize to analyze Hydro's environment with the goal of better understanding the organization's capabilities, constraints, customers, and other operational influences.

Hydro now places a greater focus on the end-consumer of power, rather than its end-point of power delivery. This change in operational philosophy has led to multiple enhancements, one being its improved situational awareness. Key personnel within Hydro are better informed of system's vulnerabilities and are better prepared to react to system events.

4.1 Internal and External Communications

Improving situational awareness starts with improved communications. Hydro has taken many actions to improve both its internal and external communications. The Daily System Status Meeting hosted by System Operations described in section 2.3.1 provides participants with daily updates on Hydro's supply capability and reserves and other conditions that could impact

[25] Flexible Alternating Current Transmission System (FACTS) are electronic devices that allow for quick adjustments to control the electrical system. The benefits they offer include improved stability of the grid, control of the flow of active and reactive power on the grid, loss minimization, and increased grid efficiency.
[26] https://www.ceati.com/collaborative-programs/transmission-distribution/pspo-power-system-planning-operations
[27] The Liberty Consulting Group, "*Review of the Newfoundland and Labrador Hydro March 4, 2015 Voltage Collapse,*" October 22, 2015, at page 10.

the reliability of the Island Interconnected System and Avalon Peninsula. Hydro Executive and Management representatives from the various functional areas, including Production, Transmission, Distribution, System Operations, Communications, and Regulatory Affairs all participate, which has improved internal communications and system status understanding within Hydro.

If Environment Canada has posted special weather statements related to wind, rain, freezing rain, and/or snow, that have the potential to negatively impact the Island Interconnected System or the Avalon Peninsula, then Hydro will host a Storm Preparation Meeting, as described in section 2.3.2. These meetings provide a structured review of the current state of the system, the preparedness of each operational area, and ultimately improve situational awareness and system reliability by ensuring that each operational area is ready to respond quickly and effectively to any severe weather impacts.

Maintenance of Hydro's systems and equipment often require planned power outages to complete. Hydro uses the Planned Outage Database and the Equipment Outage Management Tracker, described in section 2.5, to provide staff with a complete picture of existing and upcoming planned outages. The Planned Outage Database gives the ECC a single-view of all upcoming planned outages. It allows operators to see the impacts of concurrent outages and if too much risk to the system is introduced by multiple planned outages, the planned outages will be modified to reduce the level of risk to the Island Interconnected System.

The Equipment Outage Management Tracker provides a current status update for each planned outage listed in the Planned Outage Database. The outage management tracker is linked to the IAWP and captures all upcoming planed outages for generation, transmission and stations. The status in the outage management tracker is used in conjunction with the outage database to give operations a clear picture of the status of upcoming planned outage requests.

Hydro has also improved its communications with external stakeholders, including Newfoundland Power, its industrial customers, end consumers (residential), and the Board. Hydro's General Manager of System Operations will contact their Newfoundland Power counterpart to review any noteworthy items that came out of the meeting. The General Manager will also follow-up with a weekly report to Newfoundland Power. The Hydro ECC Supervisor will also follow-up with their counterpart at Newfoundland Power to discuss noteworthy items with a more detailed technical scope. This is done on a regular basis to discuss any upcoming planned outages to ensure common understanding.

The Advance Notification Protocol (see section 6.0) was developed to proactively communicate important information to customers, with clear direction on actions required, based on forecasted supply shortages and Hydro's ability to supply customers on the Island Interconnected System. Recognizing the importance and intricacies of power delivery to the Avalon Peninsula, the operating instructions and Advance Notification Protocol were updated after March 2015 to include additional protocols specific to the Avalon Peninsula.

Finally, since January 10, 2014 Hydro has prepared a daily supply and demand report for the Board, based on their reporting guidelines. The report gives the Board visibility to the current state of the Island Interconnected System. It includes the amount of electricity being generated to meet the needs of customers, the amount electricity needed by residential and business customers, the current state of generation facilities and the current and forecasted weather conditions. Hydro also produces and provides several other regular reports for the Board, including Power Outage and Incident Reports, 12 Month Rolling Generation quarterly reports, monthly Energy Supply Reports, and a semi-annual Nostradamus Report. These reports serve to provide regular updates on system status and maintain open communication and accountability of the system. Hydro's Manager, Regulatory Engineering also provides regular updates to the Board whenever there is an active or pending system issue, which could include weather events, unplanned outages, or other event impacting the integrity of the system.

All of these communication improvements make Hydro and its stakeholders more observant of the risks and current constraints facing the Island Interconnected System and Avalon Peninsula.

4.2 Improved Strategic Focus of System Operations

Changes to Hydro's organizational structure have improved Executive focus on Hydro's core mandate to provide customer with safe, least cost, reliable power and the principal functions of generation and transmission. As described in section 3.2, Transmission and Planning was merged into the System Operations organization which has helped to improve the interface between operations and planning. This change facilitates and stronger working relationship, leading to improved cooperation and outcomes.

Strategic organizational changes have also been made within System Operations. The tasks of billing, invoicing, and meter validation have moved to Customer Service. Water management has been moved from System Operations to Production and fuel/power purchase forecasting and budgeting is currently being transitioned to Production. The requirement for System Operations to report asset failures has been transitioned to Regulatory Affairs.

All of these changes allow System Operations and Transmission Planning to focus their efforts on the primary goal of maintaining a stable and reliable Island Interconnected System. This focused structure also allows the System Operations staff to plan for the creation of the NLSO (see section 7.2) and the integration of new assets that will be introduced as part of the Muskrat Falls Project.

4.2.1 Early Engagement of System Operations in IAWP

As described in section 2.4, the IAWP includes all capital and maintenance work plans for all regions for the given year. One noted improvement in the creation of the 2016 IAWP was the involvement of system operations staff in the development process. Engaging System

Operations in the planning phase allowed for proactive system balancing of generation and transmission outages.

With a view to all required outages, System Operations proactively detects conflicts and eliminates them during planning, rather than taking reactionary measures later in the maintenance season to ensure system continuity. Engaging System Operations early in the IAWP process has improved the accuracy of scheduled equipment outages.

4.2.2 Improvements to the Energy Control Center

Hydro has made extensive improvements in its Energy Control Center that provide operators with improved visibility and an enhanced holistic view of the Provincial power grid. The physical space has been reconfigured to improve operator focus on the grid and the enhanced situational awareness tools added to the ECC allow operators to proactively monitor the power grid and identify and respond to system events quickly. These improvements include:

1. **Installation of Digital Video Wall**

   Commissioned in November 2016, the new digital video wall provides flexibility and an improved holistic view of the provincial power grid than its static wall predecessor. The video wall consists of two components: a) the One Line Display and b) the Geographic Display.

   - The **One Line Display** shows the single line version of the provincial grid. It includes all power sources, transmission lines and status of each line.
   - The **Geographic Display** is part of the digital display wall and includes a digital map of Newfoundland and Labrador, and the tip of Nova Scotia.

Figure 3: ECC Display (Pre Upgrades)

Figure 4: ECC One Line Display (Post Upgrade)

2. Situational Awareness Tool

The existing situational awareness tool has been integrated with the video wall to provide operators with:

- A single-view of alarms for transmission lines approaching limits;
- A single-view to transmission line outages; and,

- Graphical indicators of the megawatts and directional flow of power on each transmission line.

These changes provide the operators with better visibility and awareness of the power grid and highlight potential issues of which they should be aware. Previously, the transmission line views were spread over multiple screens and operators only had visibility to one screen at a time. Using the new video wall, the operators get a full system view of the transmission lines without having to navigate through multiple screens.

The video wall will highlight any transmission line reaching pre-defined threshold limits for the operator and will dynamically change the color of any transmission lines outages, either planned or unplanned. Newly added directional flow indicators will become critical once the Labrador Island Link (LIL) and Maritime Link (ML) are commissioned.

3. Lightning Graphic System

The lightning graphic system is now part of the geographic display. This system provides the operator with a visual representation of the power grid, including Labrador, overlaid with lightning weather systems. Previously, this system was available on the operator's desktop screen and was not visible to the operator at all times.

Integrating the lightning graphic system with the geographic display gives operators better visibility of potential lightning strikes and allows them manage the grid while maintaining visibility to such events.

Figure 5: ECC One Line and Geographic (highlighted in red) Displays

Figure 6: ECC Geographic Display

4. Contingency Analysis Tool

The contingency analysis (CA) tool was installed on the ECC Display Wall in February 2017 and is being developed with an expected completion date in April 2017. The CA tool defines contingency violations for regional areas (zones) based upon a predetermined set of transmission line and bus violations and provides a visual means of quickly identifying where a contingency violation could potentially occur. For example, this application indicates to the system operators the single worst-case contingency on the power system at the time the application runs. CA has a number of equipment outages defined and will run a load flow for each contingency. The application then ranks each contingency in the order of severity and the results are displayed to the system operators. The severity is rated both from a voltage and thermal overload perspective. CA runs on the EMS automatically and is updated every five minutes.

Hydro has identified nine regional areas within the CA tool, five of these areas have been defined with CA rules and four others will be expanded upon once new assets come on line. Three warning levels have been developed for these regional areas including: Normal (0% CA Violation), Yellow (<5% CA Violation) and Red (<10% CA Violation). The CA warnings will be displayed as a highlighted border around each area that has a violation. This will prompt operators to drill deeper into the system to determine cause and potential solution to the CA violation.

5. Spinning Reserves Display

The spinning reserves are charted for operators to visually see spinning reserves on a real-time basis. This running chart provides operators with a visual target for monitoring and feedback. This is further enhanced by an audible alarm should the spinning reserve drop below the pre-determined target.

6. Addition of Electronic Notes to Video Wall

The use of electronic notes now takes advantage of the video wall and notes can now be added to any part of the grid, giving operators constant visibility to them. These notes are not shift-dependent and allow operators to leave notes of current system interactions/events visible on the video wall. Previously, notes could be added to a screen and were only visible on that single view of the operator's screen. This reduced the visibility of the notes across the grid for operators when focused on other screen views. The enhanced functionality of electronic notes improves communication and knowledge transfer between operators during shift changes. The type of information contained in a note would include name and contact number of a lead person on site, estimated completion time, etc. This information would be especially useful during an operator shift change if work on site transitions between shifts.

7. Creation of a Breakout Room in ECC

A breakout/meeting room was added to the ECC that allows System Operations Staff to meet and discuss ongoing issues without disturbing the on-shift operators. This additional room will allow operators to maintain their focus on management of the power grid.

8. Relocation of the Corporate Emergency Operations Center

The Corporate Emergency Operations Center (CEOC) was moved out of the ECC to a new dedicated center. This change reduces the number of individuals that would be present in the ECC during an emergency and reduces the number of person interactions with the operators, which will allow them to focus on power grid management with minimal interruption.

Moving the CEOC out of the ECC has the added benefit of giving System Operations a dedicated training facility for operators (see Section 5.0).

4.3 Staffing in Advance of Issues

Since 2016, Hydro has adopted the policy of staffing its offices and generation and transmission facilities in advance of certain system conditions to provide additional support and oversight, and improve Hydro's response time to system events.

The daily systems status meetings references upcoming weather events and provides an opportunity for those managing and monitoring the system to take proactive measures should the circumstances warrant. Depending on the severity of weather events Hydro will:

- Staff terminal stations in advance of weather impacts,
- Mobilize transmission crews closer to impacted areas, or areas that may be impacted, and,
- Mobilize operators and technical support staff to the gas and combustion turbine facilities, based on the potential of running this equipment in the event of issues with transmission or generating equipment as a result of the weather event.

All of these actions reduce travel time and gives ECC operators on-site support to help troubleshoot issues, ultimately respond faster to incidents, and reduce outage durations.

As noted in Section 6.0, since the March 4, 2015, events, the Communication Department adds staff to provide coverage during peak periods, typically 6-8am and 5-8pm in the winter months, and during any public power alerts (Power Watch, Power Warning or Power Emergency) to ensure that communications personnel are on-site and have full and immediate access to system operations information and the tools necessary to communicate effectively with the public.

Each of these preventative measures is costly but Hydro deems them important to the supply of reliable power.

4.4 A Strategy for Customer Service Excellence

Recognizing a desire to improve customer service and the customer experience, Hydro developed a Customer Service Strategy, with the purpose of creating a strategic roadmap for delivering customer service at Hydro. The purpose of the Customer Service Strategy is to outline a strategic roadmap for customer service at Hydro from 2015 - 2017. The report, entitled "*Customer Service Strategic Roadmap 2015 – 2017,*" filed with the Board on September 30, 2014, describes a vision for improving service to Hydro's industrial, utility, and retail customers. The report also identifies the vision, supporting strategies, and guiding principles to meet Hydro's current business needs and support long-term customer service strategies.

Hydro continues the execution of its Customer Service Strategy and has seen a number of improvements to software, hardware, and process and procedures. Based on survey feedback from Hydro's customers, Hydro strategy is working and Hydro looks forward to continuing to improve the service it provides to its customers. In 2017, the strategic plan will be reviewed and refreshed to take Hydro into 2020. New strategies will continue to focus on enhancing the customer experience through continuous improvement and the implementation of new technology to support processes where needed.

4.4.1 Development of an Account Management Framework

An essential requirement identified in Hydro's Account Management Framework was the creation of a dedicated account manager within Hydro's Customer Service Department to support Hydro's industrial and identified commercial customers, as well as Hydro's utility customer Newfoundland Power.

In 2016, Hydro created a Manager, Key Accounts position. The Manager, Key Accounts act as the single point of contact for its key customers, and focuses on enhancing these individual customer relationships. This allows all interactions to be managed via a single channel and be filtered throughout the Hydro organization in an efficient manner. Once a customer request is received by the Manager, Key Accounts, it is their responsibility to advocate on behalf of the customer within Hydro and pursue a resolution.

4.4.2 Implement New Customer-Focused Mobile Application

Figure 7: MyHydro Application

In April 2016, Hydro launched a new mobile and web portal platform called *MyHydro*. *MyHydro* keeps things simple and provides customers with unlimited access to their account anytime, anywhere and on any device. Users can easily and conveniently:

- View account balance, payment history, and set up payment options online,
- Subscribe to text and email notifications for planned and unplanned power outages,
- View and report power outages online,
- Subscribe to payment reminders via text and email notifications,
- Sign up for paperless e-billing and equal payment plan,
- Track and manage electricity usage in easy-to-read charts, set budget goals, compare power usage year over year, or against the average usage of residents in their neighborhood, and
- Submit service requests.

4.4.3 Improve Customer Interaction Though Phone System

Hydro implemented a new Interactive Voice Response (IVR) telephone system to better support its customers. Hydro's new enhanced IVR outage system replaces an older, unsupported system. The new system removes risk as both software and hardware components are vendor supported. The new phone system provides enhanced functionality such as automated billing and outage information. It also links the phone system and our online customer outage notification application.

4.4.4 Structured After Hours Support

Hydro established a formal after hours support arrangement with a third party vendor, TeleLink. TeleLink provides power outage handling and reporting service for after business hours customer calls related to outages. TeleLink has been trained and provided with Hydro's process for dealing with outage calls and engages on-call staff when required to follow-up with our customers to resolve an individual and widespread unplanned outage.

Hydro has seen positive results from this service and has increased the visibility into Hydro's after-hours customer calls though reporting provided by TeleLink. Hydro's customers, as well as Hydro's Energy Control Center, have experienced the benefit of this new process as it removes responsibility from the operators in the Energy Control Center for managing outage calls and allows them to focus on supporting the power system. In addition, it allows Hydro to provide customer focused service 24 hours per day.

4.4.5 Implement Transactional Customer Surveys

Hydro has implemented a transactional survey process to receive timely feedback on the service that Hydro's call center staff provides to customers. Transactional surveys are conducted through an automated outbound call service where customers are asked five questions about their most recent experience with Hydro staff in relation to the reason of their call. The survey focuses on the quality of service received, staff's knowledge, and measuring first contact satisfaction.

5.0 Improving the Corporate Emergency Response Plan

Liberty has recommended that "Hydro should implement a more robust approach to the CERP."[28]

Hydro has taken ownership of its own Corporate Emergency Response Plan(CERP) and fully staffs its Corporate Emergency Operations Center Response Team with Hydro Executive and Management personnel. Hydro's Corporate Emergency Response Plan provides clear and concise guidelines for actions to be taken by Hydro's Management Team during emergency situations. Its purpose is to ensure an effective corporate response to all emergency situations and provide guidance on all necessary emergency support actions required to reduce the probability of emergency events escalating in severity.

As part of its corporate management review process, Hydro reviews CERP on an annual basis. Since March 2015, improvements and necessary changes have been identified and are being implemented in a phased approach. These changes improve Hydro's response to emergency situations and reflect the ongoing organizational changes taking place as Hydro prepares for integration into the North American grid, and include:

1. CERP has been updated to provide dedicated resources and focus for events related to Hydro operations. CERP now includes a dedicated Hydro Executive on Call (EOC) and Hydro Corporate Emergency Operations Center (CEOC) Response Team. These individuals have autonomy for making decisions related to events impacting Hydro and would have direct knowledge of Hydro Operations resulting in quicker focused responses for Hydro events.

[28] The Liberty Consulting Group, "*Review of the Newfoundland and Labrador Hydro March 4, 2015 Voltage Collapse,*" October 22, 2015, at page 10.

2. The on-call and delegation of authority process has been streamlined. The Executive on Call now assumes the roles of Incident Commander, determines the level of response required by CERP, and assumes responsibility for managing the emergency response. Prior to this amendment, there was a dedicated Incident Commander and Deputy Incident Commander and EOC would notify the Incident Commander (or Deputy Incident Commander). The new process allows for quicker decision-making and response times.

3. The Corporate Emergency Operations Center has been moved to its own dedicated location, outside of the Energy Control Center. Previously, the CEOC was a shared location within the ECC's training facility.

4. CERP has improved the clarity of the notification and mobilization protocol. Hydro's Advance Notification Protocol Levels have been incorporated into the CERP Alert and Emergency Criteria. The EOC will be alerted when the EEC has moved into a Power Warning and will mobilize (either fully or partially) when the ECC has moved into a Power Emergency.

   CERP has also added definitions for minor and major outages to its notification protocols. These definitions are used by the EOC as part of criteria for determining whether mobilization of CERP, either full or partial mobilization.

5. CERP has updated its process for notifying and mobilizing the CERP Team. The CERP team is now notified by a third party call center vendor. The pager-system has been replaced with a third party vendor that is contracted to make contact with members of CERP. Prior to this improvement, the CERP members were contacted via pager and there was no assurity that the individual received the page. CERP members are now notified via text and required to respond. If no response is received within five minutes,

then the third party vendor will follow-up by phone call, ensuring the CERP members receive notification of the emergency.

6.0 Improvements to External Communications Processes

Following the supply disruptions in January 2014, several robust protocols and processes were developed to ensure clear and timely external communications with customers and key stakeholders. Liberty recommended the development of a Joint Storm/Outage Communication Plan with Newfoundland Power as well as the development of Advance Notification Protocols that appropriately identify potential impact in terms of the loss of power to customers.

Newfoundland and Labrador Hydro, along with Newfoundland Power, have developed a joint storm/outage communication plan that clearly outlines the roles and responsibilities of each utility along with expected timelines for communications, as well as tactics, messaging and approval processes. In addition, the utilities developed three levels of alerts to advise customers of the status of the power supply in the province. [29] The goal of the Advance Notification Protocol is to provide early information to customers when there is potential for a supply shortage, to advise on specific actions required of customers and to better prepare customers for any potential impacts.

Communications tools (including videos and infographics) were developed, along with clear messaging for each alert level, to ensure that time is not wasted during the activation of an alert aligning on appropriate messaging. In addition, during a power alert, Hydro's website is activated with a screen pop-up with clear information for customers who visit the site. Figure 7 displays the infographic developed to explain the Advance Notification Protocol.

[29] https://www.nlhydro.com/winter/advance-notification-protocol/

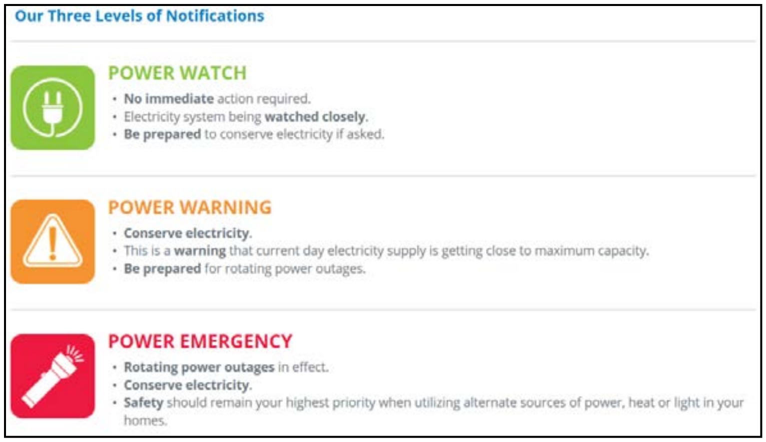


Figure 8: Advanced Notification Protocols – Levels of Notification

The original Advance Notification Protocol was developed after the supply issues experienced in January 2014 to communicate important information to customers, in advance, based on forecast generation shortages and Hydro's ability to supply customers on the Island Interconnected System.

Because the events in March 2015 were specific to the Avalon Peninsula, the Island Advance Notification Protocol was not triggered. In retrospect, power customers on Avalon Peninsula should have been notified in advance of the March 4 event. As referenced in section 2.3, Hydro is now focused on the end-consumer of power, rather than being focused on the end-point of its power delivery. This change in philosophy has led to several important enhancements. The Advance Notification Protocol and system operating procedures were expanded in April 2015 to ensure reserves are analyzed daily, from both an Island (IIS) and Avalon Peninsula perspective, to trigger any supply shortages (reference system operating instructions "Avalon Capability and Reserves (T-096)" in Section 2.3.4).

The Advance Notification Protocol public communication alerts (Power Watch, Power Warning and Power Emergency) are now able to be executed for either the Island or the Avalon Peninsula, allowing for advance communication and messaging to the appropriate customers.

As an improvement to its operational philosophy and improved communication protocols, Hydro communicates any equipment failure or system vulnerability significant in nature to its stakeholders. After the March 4 (2015) event, an additional communication process was developed to help better inform customers when major pieces of equipment are offline. The Equipment Advisory Process outlines the communications activities that will take place when major generation equipment[30] or major transmission equipment[31] is offline and unavailable to the system. Public equipment advisories are posted on Hydro's website – www.nlhydro.com/projects under the maintenance and repairs section.

Hydro has recognized the importance of educating customers and stakeholders on their provincial electricity system and is working hard to keep customers better informed about the inner workings of the provincial electricity grid. To that end, since 2014 the Hydro Communications Team has been working to develop relevant and easily understood information for customers to help them understand the overall system as well as outage and event-specific information. For example, videos, infographics and web content have been developed on the following topics;

- how to conserve energy
- power outage safety
- the Advance Notification Protocol
- how the system works
- restoring power after a distribution outage
- restoring power after a generation outage
- communications during outages
- under frequency load shedding
- how outages are planned
- power line safety

[30] Limited to generating units greater than 80MW and stand-by units
[31] 138 kV or 230 kV transmission lines

- cold load pickup

All of this customer education material can be found on Hydro's website –www.nlhydro.com and is regularly shared on Hydro's social media channels throughout the year and during specific events and/or outages.

Finally, an additional change made to communications processes after the March 4, 2015, event includes staffing of peak periods (typically 6-8am and 5-8pm in winter months) during any public power alerts (Power Watch, Power Warning or Power Emergency). This allows communications personnel to be on-site and have full and immediate access to system operations information and the tools necessary to communicate effectively with the public.

7.0 Future Improvements

In addition to the enhancements that have been detailed in this report, Hydro continues to seek improvements in support of its goal of delivering safe, reliable and least cost supply electricity to the consumer. The following items will help improve Hydro's operational reliability and will prepare Hydro for the integration of the Maritime Link, the Labrador Island Link, and the Muskrat Falls assets into the provincial electricity system.

7.1 Improving Equipment Reliability and Preventative Maintenance Programs Based on Lessons Learned

Changing the operational philosophy of Hydro involves creating a learning environment where continuous improvement is achieved by learning from the past projects and experiences. Hydro is taking an approach to learn from known operational issues and react conservatively, meaning to put plans in place to reduce risk as much as is practicable. This may involve additional operational maintenance, operational monitoring, or capital investment. For example:

1. Hydro has experienced penstock failures and generating unit seal issues at the Bay d'Espoir hydro generation facility. In review of these items, Hydro felt it important to look at the Preventative Maintenance (PM) program and ensure we are identifying these types of issues earlier. To identify issues, the PM program needs to be reviewed to ensure it is appropriate. Therefore, in 2016, Hydro contracted an external consultant to review its PM programs related to surge tanks, penstocks and generating station transformers. In an effort to continually improve its programs and long-term reliability, Hydro has asked the consultant to identify if there are gaps in the maintenance programs for these assets. Hydro will update its PM programs based on the findings of the consultant. Hydro will review the outcomes of the engagement with the outside consultant and ascertain if the external review approach provides the improvement sought for the asset management program.

2. As referenced in section 7.3, Hydro is also increasing its focus on its gas turbine units with the goal of improving their reliability. Hydro has engaged another external consultant to review all aspects of gas turbine operation and control and provide Hydro with recommendations which will further improve the reliability of these units going forward. This is being reported to the Board through a separate process.

3. Hydro also recognizes the importance of reliability at the Holyrood Thermal Generating Station until decommissioning and has refocused its maintenance efforts here. Condition assessments and inspections, along with operational experience, will dictate when Hydro requests to move ahead with investments to address reliability risks, such as the exciter controls replacement at Holyrood in the supplemental application filed with the Board February 28, 2017. This is a known reliability risk and Hydro's perspective is to remove as many such risks as is reasonable. The approach to address the risks is conservative as we are not waiting until the risk becomes so significant that it becomes an impact on the ability to serve customers.

Hydro recognizes the need to proactively improve its condition assessments, asset management programs, and ultimately, its system reliability, and will continue engage consultants for external review of its preventative maintenance programs for other corporate assets.

7.2 Creation of Newfoundland Labrador System Operator

The creation of the Newfoundland Labrador System Operator (NLSO) is an important step in the integration of the Muskrat Falls assets into the provincial electricity system, and the island's interconnection with the North American electricity market.

Industry recognized standards, such as those developed by the Federal Energy Regulatory Commission (FERC), require that electricity entities maintain a clear functional separation between the system operator and any other functions of that entity that are concerned with power production and/or marketing. [32] The purpose of this requirement is to ensure that there is no collaboration or exchange of information between affiliated business units which could impair non-discriminatory, open system access within the wider electricity market.

The NLSO will continue to exist within Hydro but will also be the system operator for the transmission and distribution system in Newfoundland and Labrador. The NLSO will represent all interests on the transmission and distribution network and will be governed by a set of rules and regulations that ensures fair and equitable treatment of all entities seeking access to the network.

The NLSO will be created by making structural and resourcing changes needed to enable the System Operations Division to function as the NLSO. Although the NLSO will reside inside

[32] The Federal Energy Regulatory Commission (FERC) is an independent agency, based in Washington, D.C., which regulates the inter-state transmission of electricity, natural gas, and oil. In the United States, and in neighboring Canadian jurisdictions, wholesale sales of electricity are typically governed by FERC's Open Access Transmission Tariff which sets out standards and other requirements governing market access and system reciprocity.

Hydro, it will act as the independent system operator[33] (ISO) for the province. It will operate the facilities owned by Hydro and Nalcor Power Supply along with interconnections with Emera's Maritime Link assets on the island.

Hydro is in the process of identifying the structural, process, and other changes required to be compliant with applicable open access obligations, including those pertaining to tariff transparency, system access, and reciprocity with jurisdictions where Nalcor takes transmission service. Section 3.2 outlines substantial organization changes that have already been made to improve the efficiency and focus of System Operations and to prepare for the creation of the NLSO. In addition to these changes, Hydro is in the process of making the following changes to support the creation of the NLSO:

1. From an operational readiness standpoint, Hydro is adding and training five System Operators to support the integration of the ML and the LIL with the IIS. This is required in order to address the new work scope assumed by the NLSO as the province's independent system operator to meet the requirements related to the standards of interchange scheduling and interconnection system reliability.Hydro's Energy Control Centre will continue to be staffed on a 24/7 basis. It will also transition to a complement of three Energy Control Center staff per shift, versus the current complement of two.

2. To meet the requirements related to the standards of interchange scheduling and interconnection system reliability, Hydro will hire:
   a) **Reliability Coordinator** – This individual has the highest level of authority and has responsibility for the grid. Reliability Coordinators have the authority, plans, and agreements in place to immediately direct reliability entities within their jurisdiction

[33] An independent system operator (ISO) is an organization that is formed at the recommendation of the Federal Energy Regulatory Commission (FERC). It coordinates, controls, and monitors the operation of the electrical power system.

to re-dispatch generation, reconfigure transmission, or reduce load to mitigate critical conditions to return the system to a reliable state.

b) **Transmission Operator** – This individual ensures the real time operating reliability of the transmission assets and manages the power system in real time and coordinates the supply of and demand for electricity in a manner that avoids fluctuations in frequency or interruptions of supply.

c) **Balancing Authority** – This individual maintains load-resource balance through the collection of generation, transmission, and load data within its metered boundaries.

7.3 Improved Standards for Measuring Gas Turbine Performance

Hydro currently uses industry standard metric Utilization Forced Outage Probability (UFOP) for measuring its gas turbines performance.[34]

While UFOP is an industry standard, as Hydro has been reviewing system reliability, Hydro determined this metric does not capture all of the necessary aspects of gas turbine asset reliability. In the "*Gas Turbine Failure Analysis Final Report*"[35] submitted to the Board on January 11, 2017, Hydro recognized and stated that an additional metric that measures the availability of its gas turbine assets is required. Material steps have been taken to identify this measure and the final selection is nearing completion. This new measure will be discussed in the May 2017 Energy Supply Risk Assessment update.

In the January 11, 2017 report, and discussed in section 7.1, Hydro also stated that it is increasing its focus on the gas turbine units with the goal of improving their reliability. To this end, Hydro has engaged external consultant Performance Improvements Ltd. (PI) to review all

[34] UFOP is defined as the probability that a generation unit will not be available when required. It is used to measure performance of standby units with low operating time such as gas turbines.
[35] Available at: http://www.pub.nf.ca/applications/IslandInterconnectedSystem/phasetwo/files/reports/From%20NLH%20-%20Hardwoods%20and%20Stephenville%20Gas%20Turbine%20Failure%20Analysis%20-%20Final%20Report%20-%20%202017-01-11.PDF

aspects of gas turbine operation and control and to provide recommendations which will further improve the reliability of these units going forward.

7.4 Review and Adoption of NERC Reliability Standards

The North American Electric Reliability Corporation (NERC) is a not-for-profit international regulatory authority with a mission is to assure the reliability and security of the bulk power systems in North America. NERC Reliability Standards define the reliability requirements for planning and operating the North American bulk power system and are developed using a results-based approach[36] that focuses on performance, risk management, and entity capabilities.[37]

Hydro recognizes the benefits that the NERC reliability standards provide and is in the preliminary stages of reviewing and assessing these standards for adoption into the Island Interconnected System. Hydro is also reviewing the impacts that the NERC reliability standard will have on Hydro's reliability and the approach it would use to implement applicable NERC reliability standards.

7.5 Service Level Agreements

Service level agreements (SLA) are contracts between a service provider and end-user that define the level of service that is expected from the service provider. The purpose of the SLA is to define what the customer will receive.

Hydro currently has SLAs in place with many of its suppliers to ensure that Hydro can get timely support and service when issues arise. Through the issues experienced in the past several

[36] Results based standards are standards that focus on required actions or results (the "what") and not necessarily the methods by which to accomplish those actions or results (the "how").
[37] http://www.nerc.com/pa/Stand/Pages/Default.aspx

years, Hydro believes that its SLAs need to be reviewed and a high level of support is required from some of its suppliers to ensure a more timely and substantial response.

One improvement in this area includes Hydro's recent long-term maintenance contract with Siemens for the Holyrood combustion turbine (CT). The Holyrood CT is an important component of the Avalon contingency reserves and securing a long-term service provider will improve access to parts inventories, improve service response times and contribute to the overall reliability of the grid.

Hydro will continue to review its SLAs with a view to renegotiating those for critical assets that are viewed as having insufficient SLAs.

7.6 Requirement for Additional Generation

In its report titled "*Review of Newfoundland and Labrador Hydro Power Supply Adequacy and Reliability Prior to and Post Muskrat Falls*", [38] Liberty recommended that "Hydro should expedite efforts to determine (a) the availability of dependable reserves from Nova Scotia or elsewhere and (b) the competitiveness of those reserves versus new Island Interconnected System generation."[39]

In order for Hydro to do a complete evaluation of the competitiveness of new sources of Island Interconnected System generation, Hydro requires an accurate estimate of each reasonable generation alternatives. One proposed Island Interconnected System generation alternative is the construction of a new hydroelectric generation turbine unit at the Bay d'Espoir Power Plant.

The new hydroelectric generation turbine (unit 8) would be identical to unit 7 and would add 154.4 MW of capacity to the Island Interconnected System. It could also be started quickly and

[38] http://www.pub.nf.ca/applications/IslandInterconnectedSystem/phasetwo/files/reports/TheLibertyConsultingGroup-PhaseTwoReport-2016-08-19.pdf
[39] Recommendation V-1

could be put on-line when coming into high load periods or kept on-line for extended periods. Given improvements in technology, a new turbine could also be more efficient than the existing turbines at Bay D'Espoir. Bay D'Espoir unit 8 is one candidate for the least-cost source of additional capacity.

Hydro is currently completing more detailed feasibility studies and cost estimated for this alternative. The results of this analysis will be used as input to the evaluation of the competitiveness of new sources of Island Interconnected System generation. The construction schedule for a new unit is estimated to be approximately 3.5 years, so Hydro is taking action to attain the required information for its review.

8.0 Conclusion

Hydro remains committed to the provision of safe, reliable and least cost supply of electricity to its customers. This report outlines the many changes that Hydro has taken since 2014 to improve its operational philosophy and reliability culture. Hydro understands that changing an organization's culture takes time and it is a large-scale undertaking that requires the organization to first change its behaviours. The current leadership and employees throughout the company are fully committed to delivering stronger service to Hydro's customers and delivering on the company's mandate.

Appendix A

Glossary of Terms

Glossary of Terms

ANP - Advanced Notification Protocols

AWP - Annual Work Plan

CEOC - Corporate Emergency Operations Center

CERP - Corporate Emergency Response Plan

ECC - Energy Control Center

EMS - Energy Management System

EOC - Executive on Call

ESRA – Energy Supply Risk Assessment

EUE - Expected Unserved Energy

HTGS – Holyrood Thermal Generating Station

IAWP - Integrated Annual Work Plan

IIS – Island Interconnected System

kV - Kilovolt

LIL - Labrador Island Link

ML - Maritime Link

MW – Megawatts

NERC - North American Electric Reliability Corporation

NLSO - Newfoundland Labrador System Operator

OTS - Operator Training Simulator

UFOP - Utilization Forced Outage Probability

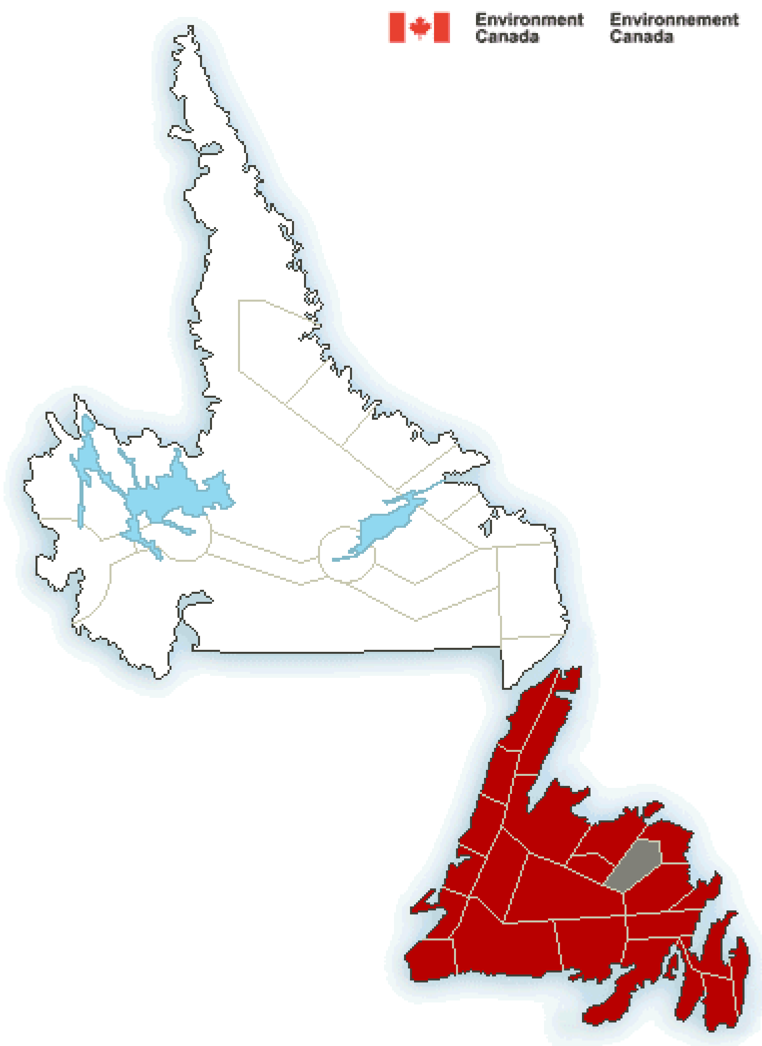
Appendix B

Daily System Status Meeting Notes

	Daily System Status Meeting - Notes		
	Topic	**Lead**	**Notes**
1	**Safety Moment and Key Messages**		http://www.nlhydro.com/winter/power-outage-safety Move towards our gaps as immediate opportunities to improve our performance and resiliency Open and honest discussion on risks and how we mitigate them Visible leadership supporting awareness and demonstrating a heightened sense of urgency
2	**System Risk/Watch**		HRD Unit #2 to come offline for cell replacement on VFD B Phase. **Water Management** Thermal generation to follow the guidelines below based on current outlook of low reservoir storage, low snowpack, and low inflows. When 2 units are available at Holyrood, the total Holyrood + Standby output shall be 400 MW. When 3 units are available at Holyrood, the total Holyrood + Standby output shall be 460 MW. *Note:* 3 units considered available when Unit 2 is available at 70 MW. **Hydrology position as of Thursday, February 4:** Total system energy storage is at 48% and all reservoirs are continuing to decline Exploits Generation is currently at 55% of normal, Red Indian Lake is 45% full and continuing to decline

			Fall/winter Inflows fourth lowest in 65 years Inflows year to date at 26% average Snowpack is at 30 - 50% of typical end of winter maximums Thermal generation has been increased for water management Holyrood generation is at maximum Standby generation increased for reliability and energy Holyrood plus standby generation averaged 431 MW over last 7 days The Avalon peak for today is 655 MW in the evening. Based on this forecast and maintaining current wind generation (2 MW) the Avalon reserves for this evening would be 265 MW with no alert. Western Avalon T5: Please see notes below in section 6b.
3	**Previous Day's Events**	System On-Call / Sys Ops	VBN T1 was taken out of service at 1732 hour due to due to burnt CT block. CBC C1 was taken out of service as the 487 relay is showing failed.
4	**Labrador Operations**	System Operations	Unit G7 HVY will be returned to service today at approximately 6pm. The unit in Postville (573) is unavailable for operation due to white smoke coming from the stack yesterday afternoon. The unit was shut down immediately and tagged out. They are currently arranging for a crew to get into Postville today from Nain where there is currently a Mechanical crew. Update Feb 03: The unit in Postville will require a partial

			dismantle to assess the issue. They are suspecting a broken liner so want to ensure they have enough time to assess the problem this week and order the repair parts by before weeks end. If damage is not too significant the unit should be up and running sometime next week depending on delivery of parts.
5	**Weather Outlook and Notifications**	Sys Ops/ Corp Relations	**Wind warning in effect for:** Avalon Peninsula North Avalon Peninsula Southeast Avalon Peninsula Southwest Boniest Peninsula Bay of Exploits Clareville and vicinity St. John's and vicinity Terra Nova Strong winds that may cause damage are expected or occurring. A low pressure system is forecast to track through central Newfoundland early on Saturday. Northwesterly winds gusting up to 110 km/h are expected along parts of the coast on Saturday behind this system. **Rainfall warning in effect for:** Avalon Peninsula Southeast Burgeo-Ramea Burin Peninsula Rain, heavy at times is expected. A low pressure system is expected to approach from the southwest



today and will cross central Newfoundland early on Saturday. Rain ahead of this system will begin near noon today and will persist into Saturday morning. Total rainfall accumulations of 25 to 35 millimetres are expected before the rain tapers off by noon on Saturday.

Winter storm warning in effect for:

Corner Brook and vicinity
Deer Lake -Humber Valley
Green Bay-White Bay
Gros Morne
Northern Peninsula East
Parson's Pond-Hawke's Bay
Port Saunders and the Straits

Hazardous winter conditions are expected. A low pressure system is forecast to track across central Newfoundland early on Saturday. Snow ahead of this system will spread northward across western Newfoundland this afternoon into this evening becoming heavy at times tonight. Total snowfall accumulations of up to 35 centimetres are expected before the snow tapers off on Saturday.

In addition, strong northerly winds are expected to develop early Saturday morning. These winds will combine with the freshly fallen snow to give reduced visibilities in blowing snow. Conditions are expected to improve Saturday afternoon.

Special weather statement in effect for:

Gander and vicinity

			A low pressure system is forecast to track through central Newfoundland early on Saturday. This system will bring warm temperatures and rain to northeastern Newfoundland tonight into Saturday morning. Total rainfall amounts are expected to be near 20 mm before the rain tapers off on Saturday.
6a	**Equipment Outages and Notifications - <u>Planned</u>**	Sys Ops/ Corp Relations	Outage is required to remove two of the mobile diesels from HRD. HRD to review and send in a detailed plan to system operations. This work will wait until HRD Unit #2 is back online.
6b	**Equipment Outages and Notifications - <u>Ongoing</u>**	Sys Ops/ Corp Relations	BDE Unit #2: It has been requested by P&C engineering that this unit not be shut down due to a start/stop relay. TL 227 remains out of service from BHL to SCV due to a landslide in the area. Section of line was taken out to be proactive and prevent possible outages and equipment damage. No customers were lost. Area assessment, extent of damage and recovery plan will be further developed when weather conditions permit and it is safe to access area. Corporate communications have been talking to parks Canada. Update Feb 05: Stantec has completed the geotechnical assessment for Parks Canada and will provide the assessment today. This will confirm the safe distance for the relocation. A detailed work plan and resources are being developed. The work will be coordinated with system operations to minimize impact to customers. Engineering design is ongoing, with surveying crews in the field, materials acquisition. All activities are being coordinated

			with Parks Canada. Western Avalon T5 still out of service. Work will be rescheduled next week based on the performance of HRD Unit#1.
7	**Island Capability / Reserves and Notifications**	Sys Ops/ Corp Relations	Island reserves are adequate at 515- 705 MW for the next 7 days. Continue to watch for Frazil ice at GCL, USL and HLK. Exploits are generating at 39 MW. Exploits generation will be adjusting output to 40 MW through discussions with System Operations. Also watching situation at Badger Wesleyville GT is out of service. There is a bearing issue and it has to be replaced. It will be out for about 6 weeks NP reported 70 MW of total hydraulic capability.
8	**Avalon Capability / Reserves and Notifications**	Sys Ops/ Corp Relations	Avalon reserves are at 235- 350 MW for the next 7 days. Three HRD units are available and unit# 2 will go offline tonight. HWD GT and HRD CT are available NP reported 41 MW of Avalon hydraulic capabilities.
9	**Standby Unit Staffing / Operation Requirements**	System Operations	This outlook reflects: Three HRD units are available and unit #2 will go offline tonight. HWD GT and HRD CT are available All Avalon transmission lines are in service.
10	**Communications - Stakeholders and Public**	Corporate Relations	
11	**Other**		

Appendix C

Severe Weather Checklist

Severe Weather Preparedness Checklist

Date:	Location:
Current and Forecasted Weather:	

Things to think about before preparing
☐ Do workers know and understand the tasks?
☐ Have all workers been given orientations? (Is there an orientation or training for working in severe weather?)
☐ Ensure Tailboards are completed prior to start of work
☐ Communicate forecasted weather conditions to all employees. Keep employees updated on changing conditions
☐ Are all proper tools available for job?
☐ Ensure employees have Proper PPE for working in extreme weather conditions
☐ Will employees be working alone? If yes, circulate the working alone procedure for review.
☐ Have environmental aspects been considered?

Emergency Information	
Emergency response plan(s) in place? ☐ **Yes**	
Has it been communicated to all required personnel? ☐ **Yes**	
Nearest medical facility:	
Emergency Contact Numbers	
1.	**3.**
2.	**4.**

Severe Weather Preparedness	
Safety	**Trucks**

☐ Consider holding safety briefings with available staff
☐ Ensure workers are familiar with the safety tools and procedures associated with severe weather
    ☐ Tailboard
    ☐ Step Back 5x5
    ☐ Proper PPE for Weather conditions
	☐ Fuel all vehicles
	☐ Ensure Distribution line trucks are stocked with critical spare parts and consumables
	☐ Equip trucks with special tools and equipment as required
	☐ Ensure distribution line workers and distribution front line supervisors have company vehicles at home
	☐ Provide on call supervisors with a company vehicle
	☐ Consider having other staff take company vehicles home
	☐ Ensure truck radios are working

Tools and Equipment	**Buildings**
☐ Test portable generators, standby duiesels and gas turbines ☐ Test tools as required ☐ Ensure fuel supply available	☐ Schedule additional snow removal ☐ Consider renting portable generators for buildings not equipped with a backup ☐ Check ability to alter temperature controls in buildings to override normal after-hour temperature settings
Substation and Generation	**Stores – Not sure this applies to us (or maybe diff name)**
☐ Consider location and availability of portable generation and portable substations. Re-deploy as required ☐ Ensure fuel Supply for system generators	☐ Ensure all stores have proper staffing levels ☐ Check stock levels for items likely needed during storms ☐ Consider confirming the supply of poles on the island

Operations Staff	**Transportation**
☐ Notify Staff of forecasted storm. Consider scheduling staff to work outside of normal working hours to ensure quick response ☐ Equip Supervisors with up to date staff listings and contact information ☐ Consider re-deploying staff to areas most likely impacted by the severe weather ☐ Put technical staff on notice of pending storm ☐ Ensure support and costumer service staffs are aware if the forcasted weather ☐ Consider enhancing staff levels at ECC and other control rooms ☐ Ensure IS support team is in place ☐ Ensure Protection and Control Engineering are aware of the pending weather and that contact information is available	☐ Where possible, put a rush on maintenance or repair work for any company vehicle ☐ Complete inspections of additional equipment and vehicles (four wheel drive trucks, snowmobiles, ATVs and specialized vehicles) ☐ Notify garages and mechanics of forecasted storm ☐ Confirm after hour contacts with government departments in the event that permits are required to re-locate portable equipment, or obtain permits in advance ☐ Confirm the availability of tractors or other equipment to relocate portable equipment ☐ Arrange for any necessary escorts
Communications	**System Security**
☐ Hold a pre-event coordination call to coordinate response activities ☐ Consider additional communication with on-call personnel to ensure rediness to respond ☐ Contact NF Power for generation Status ☐ Check availability of Satellite Phones, ensure they are charges and working ☐ Ensure appropriate staff have cell phones. Ensure adequate cell phone chargers and spare batteries are available ☐ Charge and test portable radios ☐ Test area office base station radios	☐ Make extra effort to correct any adnormal system conditions ☐ Where practical consider suspending construction on capital jobs to return the system to normal ☐ Consider developing a contingency plan for any abnormal conditions that cannot be corrected ☐ Consider protection changes above normal settings
Contractors	**Customer Service and Communications Hub**
☐ Put contractors on notice of pending storm and ask that they prepare ☐ Confirm Contractor's emergency contact information ☐ Confirm their available resources and their ability to assist ☐ Ensure Snow clearing contractors are on alert and available	☐ Confirm area connections to the communications hub. Ensure an area person is assigned to communicate with the hub ☐ Consider assigning a communications hub member to the ECC ☐ Communicate with Customer Service to determine their requirement for remote ☐ Check the availability of local Costumer Service Staff
Accommodations	**Finance**
☐ Contact local hotels to determine availability of rooms in the event that crews are moved into the area. Consider reserving a block of rooms.	☐ Arrange for numbers to be used for charging the storm. Communicate to staff
Government	**Other Utilities**
☐ Prior to the storm, confirm contacts for emergency snow clearing with the Department of Transportation ☐ Ensure updates contact lists are available for surrounding municipalities ☐ Prior to the storm, confirm ferry schedules and contact information	☐ Coordinate response with Newfoundland Power

Appendix D

Avalon Capability and Reserves (T-096)

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SYSTEM OPERATING INSTRUCTION

STATION:	GENERAL	**Inst. No.**	T-096
TITLE:	AVALON CAPABILITY AND RESERVES **	**Page** 1	**of** 5

INTRODUCTION

In order to ensure that customer service is maintained, the Energy Control Centre (ECC) shall exercise its authority to reduce risks to the Avalon capability and maintain sufficient Avalon reserves to meet current and anticipated customer demands. The ECC shall be prepared to deal with reserve deficiencies and take appropriate actions in order to maintain the reliability of the Avalon system.

Avalon reserve is required to replace generation or transmission capacity lost due to equipment forced outage, to cover performance uncertainties in generating units or to cover unanticipated increases in demand. Sufficient reserve is required to meet current and forecasted demands under a worst case contingency.

PROCEDURE

A. Calculation of *Total Avalon Capability and Available Avalon Reserve*

Total Avalon Capability is determined using load flow analysis[1] and is based on the availability of equipment on the Avalon for each day. This would include the following:

1. Generation on the Avalon (Holyrood thermal units, Hardwoods GT, Holyrood CT, Holyrood Diesels, Newfoundland Power hydro, Newfoundland Power standby, Fermeuse Wind[2] and Vale Capacity Assistance[3])
2. Transmission Availability (230 kV transmission lines on the Avalon, 138 kV transmission lines from Stony Brook – Sunnyside and Western Avalon - Holyrood)
3. Reactive resources (capacitor banks in Oxen Pond, Hardwoods and Come By Chance)

Available Avalon Reserve shall be calculated for the current day and the following six days in the manner as indicated below:

Available Avalon Reserve for each day =
Total Avalon Capability ; *less*
Forecasted Avalon Peak Load (adjusted for Voltage Reduction[4] when applicable)

[1] Base case load flows will be used to determine the Avalon Capability.
[2] Included for the current day based on actual wind output, but assumes no wind generation for the following six days.
[3] *Capacity Assistance* (when available) from Vale through operation of standby diesel units with a combined capacity of up to 15.8 MW.
[4] Up to 10 MW of Avalon load reduction (on peak) is expected to be achieved through the *Voltage Reduction* strategy. This is approximated as one-half the total Island reduction.

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SYSTEM OPERATING INSTRUCTION

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PROCEDURE (cont'd.)

B. Assessment and Notification of Available Avalon Reserve

The available Avalon reserve will be calculated for the current day and the following six days and an assessment will be made against the criteria in the table below and a notification will be issued to stakeholders when available Avalon reserve is below the stated thresholds.

Available Avalon Reserve	Expected Action	Level
> Impact of largest contingency + min reserve[5]	none	0
< Impact of largest contingency + min reserve	Prepare for potential Load Reduction	1
< Impact of largest contingency	Load Reduction	2
< Impact of ½ largest contingency	Conservation	3
Zero/deficit	Rotating Outages	4

Based on the assessment above, perform the following:

- Level 0 - If the available Avalon reserve is anticipated to be greater than the impact of the largest contingency plus min reserve, the ECC are not expected to perform any further actions, other than to advise the on-call Executive member (Exec On-call) of NLH's Corporate Emergency Response Plan (CERP), Corporate Relations and Newfoundland Power's Control Centre that the available Avalon reserve has returned to normal following a prior Level 1, 2, 3 or 4 notice.
- Level 1 - If the available Avalon reserve is anticipated to be less than the impact of the largest contingency plus min reserve, the ECC will notify Newfoundland Power's Control Centre, advising of possible requirements for load reduction to maintain sufficient Avalon reserve, if the available Avalon reserve should decrease.
- Level 2- If the available Avalon reserve is anticipated to be less than the impact of the largest contingency, the ECC will notify Exec On-call (CERP)[6] Corporate Relations[7] and Newfoundland Power's Control Centre[8], advising of load reduction strategies to maintain sufficient Avalon reserve, if the capability shortfall is not corrected.

[5] Min reserve is 35 MW.
[6] As part of the CERP, the Exec On-Call makes the decision to activate the Corporate Emergency Operations Centre (CEOC) and issues alert notifications. If activated, a partial mobilization is recommended consisting of Deputy Incident Commander, Operations Liaison and Communications Support.
[7] Corporate Relations is responsible for activating the joint communication plan between NLH and Newfoundland Power.
[8] ECC will advise the NP Control Centre once internal alignment is achieved on the alert level through the CERP process.

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SYSTEM OPERATING INSTRUCTION

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PROCEDURE (cont'd.)

- Level 3- If the available Avalon reserve is anticipated to be less than the impact of half the largest contingency, the ECC will notify Exec On-call (CERP), Corporate Relations and Newfoundland Power's Control Centre, advising of customer conservation strategies to help maintain sufficient Avalon reserve, if the capability shortfall is not corrected.
- Level 4 - If the available Avalon reserve is anticipated to approach zero or fall into a deficit, the ECC will notify Exec On-call (CERP), Corporate Relations and Newfoundland Power's Control Centre, advising of rotating outages in order to maintain supply point voltages and transmission line loadings within acceptable ranges.

The following is the standard message that will be communicated if it is anticipated that a notification is to be made under Level 1, 2, 3 or 4; or a return to Level 0:

> *"System Operations is advising that the available Avalon reserve is at a notification level [0-4] for [insert date here]. The available Avalon reserve is expected to be [insert reserve amount in MW], calculated from the total Avalon capability of [insert available capacity in MW] and a peak Avalon load forecast of [insert peak forecast in MW]."*

C. Operational requirements to cover largest contingency

The ECC shall maintain sufficient Avalon reserve to cover performance uncertainties in generating units and transmission equipment and unanticipated increases in demand. Such actions include the following: placing in service all available generating and transmission capacity, cancelling outages to generating units and transmission equipment that have a short recall, deploying all available standby resources, including Vale Capacity Assistance, cancelling Avalon industrial interruptible load and reducing Avalon load, through procedures such as public conservation notices, voltage reductions, curtailing interruptible loads and non-essential firm loads.

The ECC shall use the following guideline in the sequence outlined in order to cover the largest contingency, maintain the reliability of the Avalon and minimize service impacts to customers:

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SYSTEM OPERATING INSTRUCTION

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PROCEDURE (cont'd.)

Normal Sequence

1. Determine the Avalon capability under worst case contingency and the Avalon load threshold for operating standby units.
2. Based on this threshold and expected loads, determine requirements for staffing and potential operation for standby generation on the Avalon and notify appropriate personnel of standby staffing requirements.

To position the Avalon power system in order to cover off the single largest contingency, perform the following:

3. Ensure all NLH static reactive resources are in service (i.e. capacitor banks).
4. Request Newfoundland Power to maximize Avalon hydro generation.
5. Increase Holyrood real and reactive power up to the maximum Holyrood capability.
6. Start and load (to minimum) standby generators on the Avalon, both Hydro's and Newfoundland Power's, to cover the largest contingency once the Avalon load threshold for operation is exceeded. (At this point in time it is important to notify Avalon 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. Request Newfoundland Power to curtail its interruptible loads on the Avalon (typically up to 10 MW and can take up to 2 hours to implement).
8. Request Vale for Capacity Assistance (7.6 MW) and to put all its available capacitor banks in service.
9. Request Praxair for Capacity Assistance (5 MW).

Load Reduction

10. Cancel all non-firm power delivery to customers and ensure Avalon industrial customers are within contract limits.
11. Inform Newfoundland Power of Hydro's need to reduce supply voltage at Hardwoods and Oxen Pond to minimum levels to facilitate load reduction. Implement voltage reduction (if not already in a reduced voltage condition).
12. Request Avalon industrial customers to shed non-essential loads, informing them of system conditions.

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SYSTEM OPERATING INSTRUCTION

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PROCEDURE (cont'd.)

Rotating Outages

If the Avalon reserve continues to decrease below the minimum level, the Avalon voltages and transmission line loadings should be watched closely. Delivery point voltages at CBC (212 kV) and Hardwoods and Oxen Pond (62.5 kV) need to be maintained. Transmission line loadings need to be kept to within thermal ratings. If voltages or line loadings deviate outside of acceptable operating ranges, perform the following:

13. Request Newfoundland Power to shed load by rotating feeder interruptions.

** Part of the Emergency Response Plan

REVISION HISTORY

Version Number	Date	Description of Change
0	2015-06-26	Original Issue
1	2016-12-22	Added Praxair Capacity Assistance

PREPARED: J. Tobin	**APPROVED:**

Appendix E

Generation Reserves (T-001)

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SYSTEM OPERATING INSTRUCTION

STATION:	GENERAL	**Inst. No.**	T-001
TITLE:	GENERATION RESERVES *, **	**Page** 1	**of** 5

INTRODUCTION

In order to ensure that customer service is maintained, the Energy Control Centre (ECC) shall exercise its authority to reduce risks to the generation supply and maintain sufficient generation reserves to meet current and anticipated customer demands. The ECC shall be prepared to deal with generation shortages and take appropriate actions in order to maintain the reliability of the Island Interconnected System.

Generation reserve[1] is required to replace generation capacity lost due to an equipment forced outage, to cover performance uncertainties in generating units or to cover unanticipated increases in demand. Sufficient generation reserve is required to meet current and forecasted demands under a contingency of the largest generating unit.

PROCEDURE

A. Calculation of *Available Generation Reserve*[2]

Available generation reserve shall be calculated for the current day and the following six days in the manner as indicated below:

Available Generation Reserve for each day =
Available Generation of NLH (Hydro + Thermal + *Standby*[3] + *Purchases*[4]); *plus*
Available Generation of NP (Hydro + Standby); *plus*
Available Generation of DLP (60 Hz Hydro); *plus*
Capacity Assistance of Vale (Standby)[5]; *less*
Forecasted Island Peak Load (adjusted for CBPP Capacity Assistance[6] and Voltage Reduction[7])

A plot is provided on the EMSView – Production - Load Forecast page for reference.

[1] *Generation Reserve* is defined as the quantity of available generation supply that is in excess of demand, and includes spinning reserve[8]. It is equal to Available Generation Supply less Current / Forecasted Demand.
[2] *Available Generation Reserve* is associated with generation that is in service or standby generation that can be placed in service within 20 minutes. NP's mobile generation may take up to 2 hours to place in service.
[3] *Standby* generation includes combustion turbine / diesel generation, including the new CT at Holyrood.
[4] *NLH Purchases* includes wind for the current day based on actual wind output, but assumes no wind generation for the following six days.
[5] *Capacity Assistance* (when available) from Vale through operation of standby diesel units with a combined capacity of 10.8 MW.
[6] *Capacity Assistance* (when available) from CBPP through load interruption in 20, 40 or 60 MW blocks.
[7] Up to 20 MW of load reduction (on peak) is expected to be achieved through the *Voltage Reduction* strategy.
[8] *Spinning reserve* is defined as unloaded generation that is synchronized to the power system and ready to serve additional demand.

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SYSTEM OPERATING INSTRUCTION

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PROCEDURE (cont'd.)

B. Assessment and Notification of Available Generation Reserve

The available generation reserve will be calculated for the current day and the following six days and an assessment will be made against the criteria in the table below. A notification will be issued to stakeholders when available generation reserve is below the stated thresholds for anytime within the next week.

Available Reserve	Expected Action	Level
> Largest Generating Unit + min. spinning reserve	none	0
< Largest Generating Unit + min. spinning reserve	Prepare for Potential Load Reduction	1
< Largest Generating Unit	Load Reduction	2
< ½ Largest Generating Unit	Conservation	3
Zero/deficit; hold f=59.8 Hz	Rotating Outages	4

Based on the assessment above, perform the following:

- Level 0 - If the available reserve is anticipated to be greater than the largest available generating unit capacity plus minimum spinning reserve, the ECC are not expected to perform any further actions, other than to advise the on-call Executive member (Exec On-call) of NLH's Corporate Emergency Response Plan (CERP), Corporate Relations and Newfoundland Power that available reserve has returned to normal following a prior Level 1, 2, 3 or 4 notice.
- Level 1 - If the available reserve is anticipated to be <u>less than the largest available generating unit capacity plus the minimum spinning reserve</u>, the ECC will notify Newfoundland Power's Control Centre, advising of possible requirements for load reduction to maintain sufficient spinning reserve, if the available generation reserve should decrease.
- Level 2 - If the available reserve is anticipated to be <u>less than the largest available generating unit capacity</u>, the ECC will notify Exec On-Call (CERP)[9], Corporate Relations[10] and Newfoundland Power, advising of load reduction strategies to maintain sufficient spinning reserve, if the generation shortfall is not corrected.

[9] As part of the CERP, the Exec On-Call makes the decision to activate the Corporate Emergency Operations Centre (CEOC) and issues alert notifications.
[10] Corporate Relations is responsible for activating the joint communication plan between NLH and Newfoundland Power.

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SYSTEM OPERATING INSTRUCTION

STATION:	GENERAL	**Inst. No.**	T-001
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PROCEDURE (cont'd.)

- Level 3 - If the available reserve is anticipated to be less than half of the largest available generating unit capacity, the ECC will notify Exec On-call (CERP), Corporate Relations and Newfoundland Power, advising of a requirement for customer conservation strategies to help maintain sufficient spinning reserve, if the generation shortfall is not corrected.
- Level 4 - If the available reserve is anticipated to approach zero or fall into a deficit, the ECC will notify Exec On-call (CERP), Corporate Relations and Newfoundland Power, advising of a requirement for rotating outages to help maintain frequency near the 60 Hertz standard, if the generation shortfall is not corrected.

The following is the standard message that will be communicated if it is anticipated that a notification is to be made under Level 1, 2, 3 or 4; or a return to Level 0:

"System Operations is advising that the available Island generation reserve is at a notification level [0-4] for [insert date here]. The available generation reserve is expected to be [insert reserve amount in MW], calculated from an available generation capacity of [insert available capacity in MW] and a peak load forecast of [insert peak forecast in MW]."

C. Maintaining Spinning Reserve

The ECC shall maintain sufficient spinning reserve to cover performance uncertainties in generating units, especially wind and other variable generation, and unanticipated increases in demand. The ECC will take appropriate action to maintain a minimum spinning reserve level equal to 70 MW. Such actions include the following: placing in service all available generating capacity, cancelling outages to generating units that have a short recall, deploying all available standby resources, including CBPP and Vale Capacity Assistance, cancelling industrial interruptible load and reducing system load, through procedures such as public conservation notices, voltage reductions, curtailing interruptible loads and non-essential firm loads.

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SYSTEM OPERATING INSTRUCTION

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PROCEDURE (cont'd.)

The following guideline shall be followed by the ECC Shift Supervisor and System Operator in the sequence outlined in order to maintain sufficient spinning reserve, maintain the reliability of the Island Interconnected System and minimize service impacts to customers:

Normal Sequence

1. Place in service all of Hydro's available hydroelectric generation.
2. Request Newfoundland Power to maximize their hydroelectric generation.
3. Make a Capacity Request of Deer Lake Power to maximize their hydroelectric generation.
4. Request Non-Utility Generators to maximize their hydroelectric and wind generation.
5. Maximize Holyrood thermal generation.
6. 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, while holding the least efficient NLH standby combustion turbine unit in reserve. (At this point in time it is important to 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. Request Newfoundland Power to curtail its interruptible loads (typically up to 10 MW and can take up to 2 hours to implement).
8. Request Corner Brook Pulp and Paper for Capacity Assistance (20, 40 or 60 MW).
9. Request Vale for Capacity Assistance (7.6 MW).
10. Request Praxair for Capacity Assistance (5 MW).
11. Start and load the remaining NLH standby combustion turbine unit.

Load Reduction

12. Cancel all non-firm power delivery to customers and ensure all industrial customers are within contract limits.
13. 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. Implement voltage reduction.
14. Request Newfoundland Power to implement voltage reduction on its system.

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SYSTEM OPERATING INSTRUCTION

STATION:	GENERAL	**Inst. No.**	T-001
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PROCEDURE (cont'd.)

Load Reduction (cont'd)

15. Request industrial customers to shed non-essential loads, informing them of system conditions.
16. Request Corner Brook Pulp and Paper Supplemental Capacity Assistance (to a maximum of 30 MW). Note that this is above the Capacity Assistance request and a request for the full 30 MW will likely reduce CBPP Mill load to that required for essential services. Upon request for Supplemental Capacity Assistance, arrangements should be made with TRO-Central to close the load break bus tie switch B2B4-1 at Massey Drive.

Rotating Outages

If the spinning reserve continues to decrease below the minimum level, the system frequency should be watched closely. In order to minimize outages to customers, utilize the reserve as much as possible and maintain the system frequency at 59.8 Hz.

17. Request Newfoundland Power to shed load by rotating feeder interruptions. At the same time, shed load by rotating feeder interruptions in Hydro's rural distribution areas. Follow instruction for rotating outages, T-042.

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

REVISION HISTORY

Version Number	Date	Description of Change
0	1992-07-16	Original Issue
13	2016-12-22	Added Praxair Capacity Assistance
PREPARED: J. Tobin		**APPROVED:**

Appendix F

Outage Readiness Tracker

Equipment Outage	MOS Outage #	Customer Outage		PETS		Baseline %	Start	Finish		Outage Request Submitted?			WPC Requirements Reviewed?						Field Isolation Plan Required?				Energization/Start-Up Plan Required?									Commissioning Plan & Procedures				Resource Confirmation			
										Submitted	System Outage #	Approved	None	TAWP	OAWP	PC1 Submittal (7 Days Prior)	Submitted	Approved	Required		Plan Finalized (7 Days Prior)	Approved	Required		1st Draft (28 Days Prior)	Received	Plan Finalized (14 Days Prior)	Approved	Extra Outage Required		System Outage #	Plan Required		Plan Prepared (1 Day Prior)	Approved	Internal External Manpower (7 Days Prior)	Confirmed	Equipment Parts Deliverables (7 Days Prior)	Confirmed
																			Y	N			Y	N					Y	N		Y	N						
BDE B3T6	T-C024	No	☐	PETS	☑	100%	9-May-16	25-Jun-16	☐	☑	9533	☑	☐	☐	☑	2-May-16	☑	☑	☑	☐	2-May-16	☑	☑	☐	28-May-16	☑	11-Jun-16	☑	☑	☐	9689	☑	☐	8-May-16	☑	2-May-16	☑	2-May-16	☑
BDE B2T3	T-C021	No	☐	PETS	☑	92%	6-Jun-16	23-Jul-16	☐	☑	9535	☑	☐	☐	☑	30-May-16	☑	☑	☑	☐	30-May-16	☑	☑	☐	25-Jun-16	☐	9-Jul-16	☐	☑	☐		☑	☐	5-Jun-16	☑	30-May-16	☑	30-May-16	☑
BUC L05L33 Breaker PM	T-C164	No	☐		☐	100%	21-Jun-16	24-Jun-16	☐	☑	9627	☑	☐	☑	☐		☐	☐	☐	☑		☐	☐	☑		☐		☐	☐	☐		☐	☑		☐	14-Jun-16	☑	14-Jun-16	☑
BDE T3 Transformer Protection	T-C211	No	☐	PETS	☑	100%	6-Jun-16	23-Jul-16	☐	☑	9676	☑	☑	☐	☐		☐	☐	☑	☐	30-May-16	☑	☐	☑		☐		☐	☐	☐		☑	☐	5-Jun-16	☑	30-May-16	☑	30-May-16	☑
HWD B7B8 breaker replacement	T-C015	No	☐	PETS	☑	96%	30-May-16	14-Jul-16	☐	☑	9649	☑	☐	☑	☐		☐	☐	☑	☐	23-May-16	☑	☑	☐	16-Jun-16	☑	30-Jun-16	☐	☐	☑		☑	☐	29-May-16	☑	23-May-16	☑	23-May-16	☑
HRD B12L42 Breaker replacement	T-C013	No	☐	PETS	☑	96%	28-May-16	14-Jul-16	☐	☑	9602	☑	☐	☑	☐		☐	☐	☑	☐	21-May-16	☑	☑	☐	16-Jun-16	☑	30-Jun-16	☐	☐	☑		☑	☐	27-May-16	☑	21-May-16	☑	21-May-16	☑
TL203 Insulator Replacements, Outage #1	T-C048	No	☐	PETS	☑	100%	13-Jun-16	11-Jul-16	☐	☑	9650	☑	☐	☐	☑	6-Jun-16	☑	☑	☐	☑		☐	☐	☑		☐		☐	☐	☐		☐	☑		☐	6-Jun-16	☑	6-Jun-16	☑
TL242 Replace Protection Systems	T-C006	No	☐	PETS	☑	100%	6-Jun-16	29-Jun-16	☐	☑	9603	☑	☑	☐	☐		☐	☐	☐	☑		☐	☑	☐	1-Jun-16	☑	15-Jun-16	☑	☑	☐		☑	☐	5-Jun-16	☑	30-May-16	☑	30-May-16	☑
TL242 reconfiguration around soldiers pond	T-C007	No	☐		☐	100%	6-Jun-16	29-Jun-16	☐	☑	9604	☑	☐	☐	☑	30-May-16	☑	☑	☐	☑		☐	☐	☑		☐		☐	☐	☐		☐	☑		☐	30-May-16	☑	30-May-16	☑
BDE T4 Transformer Protection Replacement	T-C269	No	☐	PETS	☑	100%	13-Jun-16	8-Jul-16	☐	☑	9722	☑	☑	☐	☐		☐	☐	☐	☑		☐	☐	☑		☐		☐	☐	☐		☑	☐	12-Jun-16	☑	6-Jun-16	☑	6-Jun-16	☑
MDR T2 A-B phase PT replacement	T-C188	No	☐	PETS	☑	92%	29-Jun-16	30-Jun-16	☐	☑	9710	☐	☐	☑	☐		☐	☐	☐	☑		☐	☐	☑		☐		☐	☐	☐		☐	☑		☐	22-Jun-16	☑	22-Jun-16	☑
BUC L05L33-1, B1L05-2, L05G disconnect PMs	T-C166	No	☐		☐	100%	20-Jun-16	20-Jun-16	☑	☑	9728	☑	☐	☐	☑	13-Jun-16	☑	☑	☐	☑		☐	☐	☑		☐		☐	☐	☐		☐	☑		☐	13-Jun-16	☑	13-Jun-16	☑
MDR B5L11-2, L11G disconnect PM, doble CTs	T-C191	No	☐		☐	92%	17-Jun-16	17-Jun-16	☐	☑	9714	☐	☐	☐	☑	10-Jun-16	☑	☑	☐	☑		☐	☐	☑		☐		☐	☐	☐		☐	☑		☐	10-Jun-16	☑	10-Jun-16	☑
WAV B4 outage. L64G CM, PT doble	T-C134	No	☐		☐	100%	20-Jun-16	21-Jun-16	☑	☑	9661	☑	☐	☐	☑	13-Jun-16	☑	☑	☐	☑		☐	☐	☑		☐		☐	☐	☐		☐	☑		☐	13-Jun-16	☑	13-Jun-16	☑
HRD TS T3 Oil Replacement	T-C221	No	☐	PETS	☑	100%	20-Jun-16	1-Jul-16	☐	☑	9769	☑	☐	☐	☑	13-Jun-16	☑	☑	☐	☑		☐	☐	☑		☐		☐	☐	☐		☐	☑		☐	13-Jun-16	☑	13-Jun-16	☑
BBK L400T2 Breaker Replacement	T-C027	No	☐	PETS	☑	92%	20-Jun-16	5-Aug-16	☐	☑	9543	☑	☐	☑	☐		☐	☐	☑	☐	13-Jun-16	☑	☐	☑		☐		☐	☐	☐		☑	☐	19-Jun-16	☐	13-Jun-16	☑	13-Jun-16	☑
WAV B2T1 Breaker Replacement	T-C028	No	☐	PETS	☑	92%	21-Jun-16	5-Aug-16	☐	☑	9652	☑	☐	☑	☐		☐	☐	☑	☐	14-Jun-16	☑	☐	☑		☐		☐	☐	☐		☑	☐	20-Jun-16	☐	14-Jun-16	☑	14-Jun-16	☑
BDE B3 outage. To install new B3T6 breaker	T-C253	No	☐	PETS	☑	100%	21-Jun-16	21-Jun-16	☑	☑	9689	☑	☑	☐	☐		☐	☐	☐	☑		☐	☐	☑		☐		☐	☐	☐		☐	☑		☐	14-Jun-16	☑	14-Jun-16	☑
BDE Unit #7, T7 replacement	T-C010	No	☐	PETS	☑	79%	26-Jun-16	19-Aug-16	☐	☑	9545	☑	☐	☐	☑	19-Jun-16	☑	☐	☑	☐	19-Jun-16	☑	☑	☐	22-Jul-16	☐	5-Aug-16	☐	☐	☑		☑	☐	25-Jun-16	☐	19-Jun-16	☑	19-Jun-16	☑
BDE B9B10 breaker PM. B9B10-1 & B9B10-2 PM CTs	T-C101	No	☐		☐	92%	27-Jun-16	28-Jun-16	☐	☑	9745	☐	☐	☑	☐		☐	☐	☐	☑		☐	☐	☑		☐		☐	☐	☐		☐	☑		☐	20-Jun-16	☑	20-Jun-16	☑
HRD B3L18 complete auxiliary contacts	T-C251	No	☐	PETS	☑	100%	21-Jun-16	24-Jun-16	☐	☑	9777	☑	☑	☐	☐		☐	☐	☐	☑		☐	☐	☑		☐		☐	☐	☐		☐	☑		☐	14-Jun-16	☑	14-Jun-16	☑
MDR B2 doble PTs	T-C187	No	☐		☐	92%	28-Jun-16	28-Jun-16	☐	☑	9766	☐	☐	☐	☑	21-Jun-16	☑	☑	☐	☑		☐	☐	☑		☐		☐	☐	☐		☐	☑		☐	21-Jun-16	☑	21-Jun-16	☑
BDE B1B2 Breaker Replacement	T-C045	No	☐	PETS	☑	83%	30-Jun-16	16-Aug-16	☐	☑	9179	☑	☐	☑	☐		☐	☐	☑	☐	23-Jun-16	☑	☑	☐	19-Jul-16	☐	2-Aug-16	☐	☑	☐		☑	☐	29-Jun-16	☐	23-Jun-16	☑	23-Jun-16	☑
BDE T7 Transformer Protection Replacement	T-C215	No	☐	PETS	☑	83%	4-Jul-16	19-Aug-16	☐	☑	9545	☑	☑	☐	☐		☐	☐	☑	☐	27-Jun-16	☑	☐	☑		☐		☐	☐	☐		☑	☐	3-Jul-16	☐	27-Jun-16	☐	27-Jun-16	☑
OPD B1L36 Breaker Replacement	T-C019	No	☐	PETS	☑	58%	4-Jul-16	20-Aug-16	☐	☑	9767	☑	☐	☑	☐		☐	☐	☑	☐	27-Jun-16	☐	☑	☐	23-Jul-16	☐	6-Aug-16	☐	☑	☐		☑	☐	3-Jul-16	☐	27-Jun-16	☐	27-Jun-16	☐
BDE B13T12 replacement. T12 outage (TL220 to be feed via T10)	T-C069	No	☐	PETS	☑	83%	4-Jul-16	18-Jul-16	☐	☑	9785	☐	☐	☐	☑	27-Jun-16	☐	☐	☐	☑		☐	☐	☑		☐		☐	☐	☐		☐	☑		☐	27-Jun-16	☑	27-Jun-16	☑
IRV B1L24 overhaul	T-C168	No	☐		☐	67%	4-Jul-16	11-Jul-16	☐	☐		☐	☐	☑	☐		☐	☐	☐	☑		☐	☐	☑		☐		☐	☐	☐		☐	☑		☐	27-Jun-16	☐	27-Jun-16	☐
BDE B9 outage. Install Mobile Sub (to bypass T11, T-C232), split B13, Isolate T12.	T-C237	YES	☑	PETS	☑	33%	4-Jul-16	4-Jul-16	☐	☑	9784	☐	☐	☐	☑	27-Jun-16	☐	☐	☐	☐		☐	☐	☐		☐		☐	☐	☐		☐	☐		☐	27-Jun-16	☑	27-Jun-16	☑
TL233 Replace Crossarm on Structure #386	T-C270	No	☐		☐	83%	5-Jul-16	5-Jul-16	☐	☐	9656	☑	☐	☐	☑	28-Jun-16	☐	☐	☐	☑		☐	☐	☑		☐		☐	☐	☐		☐	☑		☐	28-Jun-16	☑	28-Jun-16	☑
CRV TS L20T1 PM	T-C174	YES	☑		☐	33%	5-Jul-16	5-Jul-16	☐	☑	9784	☐	☐	☐	☑	28-Jun-16	☐	☐	☐	☐		☐	☐	☐		☐		☐	☐	☐		☐	☐		☐	28-Jun-16	☑	28-Jun-16	☑
CRV TS T1 PM	T-C272	YES	☑		☐	33%	5-Jul-16	5-Jul-16	☐	☑	9784	☐	☐	☐	☑	28-Jun-16	☐	☐	☐	☐		☐	☐	☐		☐		☐	☐	☐		☐	☐		☐	28-Jun-16	☑	28-Jun-16	☑
OPD B5 outage. B2B5-2, B5C1-1, B5T3-1 Disconnect PMs. PTs	T-C128	No	☐		☐	92%	6-Jul-16	8-Jul-16	☐	☑	9663	☑	☐	☐	☑	29-Jun-16	☐	☐	☐	☑		☐	☐	☑		☐		☐	☐	☐		☐	☑		☐	29-Jun-16	☑	29-Jun-16	☑
OPD B2B5 doble	T-C127	No	☐		☐	92%	6-Jul-16	8-Jul-16	☐	☑	9663	☑	☐	☐	☑	29-Jun-16	☐	☐	☐	☑		☐	☐	☑		☐		☐	☐	☐		☐	☑		☐	29-Jun-16	☑	29-Jun-16	☑
IRV B1L23 overhaul	T-C169	No	☐		☐	17%	11-Jul-16	18-Jul-16	☐	☐		☐	☐	☑	☐		☐	☐	☐	☐		☐	☐	☐		☐		☐	☐	☐		☐	☐		☐	4-Jul-16	☐	4-Jul-16	☐
HWD Bus 2 outage, B2L42-1,B2T4, B2T3 disconnect PMs, B2 PT Doble. Will take T242 out of service.	T-C092	No	☐		☐	33%	12-Jul-16	12-Jul-16	☐	☑	9605	☐	☐	☐	☑	5-Jul-16	☐	☐	☐	☐		☐	☐	☐		☐		☐	☐	☐		☐	☐		☐	5-Jul-16	☑	5-Jul-16	☑
CBFC 129/129GR/129SP/229/229GR/29MB disconnect PMs	T-C177	No	☐		☐	92%	12-Jul-16	15-Jul-16	☐	☑	9575	☐	☐	☑	☐		☐	☐	☐	☑		☐	☐	☑		☐		☐	☐	☐		☐	☑		☐	5-Jul-16	☑	5-Jul-16	☑
HWD T3 PM	T-C110	No	☐		☐	42%	13-Jul-16	14-Jul-16	☐	☑	9782	☐	☐	☑	☐		☐	☐	☐	☐		☐	☐	☐		☐		☐	☐	☐		☐	☐		☐	6-Jul-16	☑	6-Jul-16	☑
WAV T3 tap changer leak test	T-C137	No	☐		☐	25%	13-Jul-16	17-Jul-16	☐	☑	9290	☐	☐	☑	☐		☐	☐	☐	☐		☐	☐	☐		☐		☐	☐	☐		☐	☐		☐	6-Jul-16	☐	6-Jul-16	☐
HWD B7T1 replacement	T-C014	No	☐		☐	17%	15-Jul-16	31-Aug-16	☐	☐		☐	☐	☑	☐		☐	☐	☐	☐		☐	☐	☐		☐		☐	☐	☐		☐	☐		☐	8-Jul-16	☐	8-Jul-16	☐
OPD B5C1 replacement	T-C129	No	☐		☐	17%	16-Jul-16	30-Aug-16	☐	☐		☐	☐	☑	☐		☐	☐	☐	☐		☐	☐	☐		☐		☐	☐	☐		☐	☐		☐	9-Jul-16	☐	9-Jul-16	☐

newfoundland labrador
hydro
a nalcor energy company

Hydro Place. 500 Columbus Drive.
P.O. Box 12400. St. John's. NL
Canada A1B 4K7
t. 709.737.1400 f. 709.737.1800
www.nlh.nl.ca

May 19, 2016

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

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

Dear Ms. Blundon:

Re: An Application by Newfoundland and Labrador Hydro (Hydro) pursuant to Subsection 41(3) of the Act for the approval of the Gas Generator Engine Refurbishments at the Hardwoods Gas Turbine Plant and the Stephenville Gas Turbine Plant

Please find enclosed the original and 12 copies of the above-noted Application, plus supporting affidavit, project proposal, and draft order.

The proposed project involves the refurbishment of gas generator engine, End A engine, serial number 202205, at the Hardwoods Gas Turbine Plant and gas generator engine, End A engine, serial number 202204, at the Stephenville Gas Turbine Plant which is necessary for the supply of safe and adequate and reliable power to the Island Interconnected System.

Should you have any questions, please contact the undersigned.

Yours truly,

NEWFOUNDLAND AND LABRADOR HYDRO

Tracey Pennell

Tracey L. Pennell
Legal Counsel

TLP/bs

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

IN THE MATTER OF the *Electrical Power Control Act,* RSNL 1994, Chapter E-5.1 (the *EPCA*) and the *Public Utilities Act*, RSNL 1990, Chapter P-47 (the *Act*), and regulations thereunder;

AND IN THE MATTER OF an Application by Newfoundland and Labrador Hydro (Hydro) pursuant to Subsection 41(3) of the *Act*, for approval of the Gas Generator Engine Refurbishments at the Hardwoods Gas Turbine Plant and the Stephenville Gas Turbine Plant

TO: The Board of Commissioners of Public Utilities (the Board)

THE APPLICATION OF NEWFOUNDLAND AND LABRADOR HYDRO (Hydro) STATES THAT:

1. Hydro is a corporation continued and existing under the *Hydro Corporation Act, 2007*, is a public utility within the meaning of the *Act* and is subject to the provisions of the *Electrical Power Control Act, 1994*.

2. Hydro is the primary generator of electricity in Newfoundland and Labrador. As part of its generating assets, Hydro owns and operates two 50 MW gas turbine plants. The Hardwoods Gas Turbine Plant (Hardwoods) was constructed in 1976 and is located in the west end of the city of St. John's. The Stephenville Gas Turbine Plant was commissioned in 1975 and is located in the town of Stephenville. Both plants operate in either generation mode to provide peak and emergency power or as synchronous condensers to provide voltage support to the Island Interconnected System.

3. On February 8, 2016, gas generator engine, End A engine, serial number 202205, at Hardwoods failed resulting in internal damage to the housing and turbine sections of the engine. On March 26, 2016 gas generator engine, End A engine, serial number 202204, at Stephenville failed causing internal damage. Both failed engines have been removed from service and cannot be operated. As a result of the aforementioned damage, End A

engine, serial number 202205, at Hardwoods and End A engine, serial number 202204, at Stephenville, must be refurbished.

4. Hydro is recommending that End A engine, serial number 202205 at Hardwoods and End A engine, serial number 202204 at Stephenville be refurbished. Details regarding Hydro's proposal to refurbish these gas generator engines are contained in the attached project proposal document.

5. The availability and reliability of Hardwoods and Stephenville is critical to ensure voltage regulation of the Island Interconnected System. These facilities are also important for the generation of peak and emergency power and for planned generation or transmission outages. The refurbishment of these gas generator engines are required to return Hardwoods and Stephenville to their full capability.

6. The estimated cost of this project is $3,047,100 and is expected to be completed in November 2016.

7. The Applicant submits that the proposed refurbishment of the gas generator engines at Hardwoods and Stephenville is necessary to ensure that the Hydro can continue to provide service which is safe and adequate and just and reasonable as required by Section 37 of the *Act*. An Engineering Report supporting this supplemental capital application is attached.

8. Hydro therefore makes Application for an Order pursuant to section 41(3) of the *Act* approving the refurbishment of gas generator, End A engine, serial number 202205, at Hardwoods and gas generator, End A engine, serial number 202204, at Stephenville at an estimated capital cost of $3,047,100 as set out in this Application and in the attached project description and justification document.

DATED at St. John's, in the Province of Newfoundland and Labrador, this 19 day of May, 2016.

Tracey Pennell

Tracey L. Pennell
Counsel for the Applicant
Newfoundland and Labrador Hydro
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St. John's, NL A1B 4K7
Telephone: (709) 778-6671
Facsimile: (709) 737-1782

IN THE MATTER OF the *Electrical Power Control Act,* RSNL 1994, Chapter E-5.1 (the *EPCA*) and the *Public Utilities Act*, RSNL 1990, Chapter P-47 (the *Act*), and regulations thereunder;

AND IN THE MATTER OF an Application by Newfoundland and Labrador Hydro (Hydro) pursuant to Subsection 41(3) of the *Act*, for approval of the Gas Generator Engine Refurbishments at the Hardwoods Gas Turbine Plant and the Stephenville Gas Turbine Plant.

AFFIDAVIT

I, Scott Crosbie, Professional Engineer, of St. John's in the Province of Newfoundland and Labrador, make oath and say as follows:

1. I am the General Manager of Thermal Production of Newfoundland and Labrador Hydro, the Applicant named in the attached Application.
2. I have read and understand the foregoing Application.
3. I have personal knowledge of the facts contained therein, except where otherwise indicated, and they are true to the best of my knowledge, information and belief.

SWORN at St. John's in the)
Province of Newfoundland and)
Labrador)
this 19 day of May 2016,)
before me:)

Tracey Pennell
Barrister – Newfoundland and Labrador

Scott Crosbie
Scott Crosbie

(DRAFT ORDER)
NEWFOUNDLAND AND LABRADOR
BOARD OF COMMISSIONERS OF PUBLIC UTILITIES

AN ORDER OF THE BOARD

NO. P.U. __ (2016)

IN THE MATTER OF the *Electrical Power Control Act,* RSNL 1994, Chapter E-5.1 (the *EPCA*) and the *Public Utilities Act*, RSNL 1990, Chapter P-47 (the *Act*), and regulations thereunder;

AND IN THE MATTER OF an Application by Newfoundland and Labrador Hydro (Hydro) pursuant to Subsection 41(3) of the Act, for approval of the Gas Generator Engine Refurbishments at the Hardwoods Gas Turbine Plant and the Stephenville Gas Turbine Plant.

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WHEREAS the Applicant is a corporation continued and existing under the *Hydro Corporation Act, 2007,* is a public utility within the meaning of the Act and is subject to the provisions of the *Electrical Power Control Act*, 1994; and

WHEREAS Section 41(3) of the Act requires that a public utility not proceed with the construction, purchase or lease of improvements or additions to its property where:

a) the cost of 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 prior approval of the Board; and

WHEREAS in Order No. P.U. 33(2015) the Board approved Hydro's 2016 Capital Budget in the amount of $183,082,800; and

WHEREAS on February 8, 2016, gas generator engine, End A engine, serial number 202205, at the Hardwoods Gas Turbine Plant failed resulting in internal damage to the housing and turbine sections of the engine. On March 26, 2016 gas generator engine, End A engine, serial number 202204, at the Stephenville Gas Turbine Plant also failed causing internal damage; and

WHEREAS the Hardwoods Gas Turbine Plant and the Stephenville Gas Turbine Plant are required to provide voltage regulation on the Island Interconnected System, to provide generation of peak and emergency power, and for planned generation or transmission outages; and

WHEREAS on May 18, 2016 Hydro applied to the Board for approval to refurbish the two damaged gas generator engines in order to return the Hardwoods Gas Turbine Plant and the Stephenville Gas Turbine Plant to their full capability; and

WHEREAS the capital cost of the project is anticipated to be $3,047,100; and

WHEREAS the Board is satisfied that the refurbishment of gas generator engine, End A engine, serial number 202205, at the Hardwoods Gas Turbine Plant and gas generator engine, End A engine, serial number 202204, at the Stephenville Gas Turbine Plant, is necessary and reasonable to allow Hydro to provide service and facilities which are reasonably safe and adequate and just and reasonable.

IT IS THEREFORE ORDERED THAT:

1. The proposed capital expenditure to refurbish gas generator engine, End A engine, serial number 202205, at the Hardwoods Gas Turbine Plant and gas generator engine, End A engine, serial number 202204, at the Stephenville Gas Turbine Plant of $3,047,100 is approved.

2. Hydro shall pay all expenses of the Board arising from this Application.

DATED at St. John's, Newfoundland and Labrador, this day of , 2016.

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A REPORT TO
THE BOARD OF COMMISSIONERS OF PUBLIC UTILITIES

REGISTERED PROFESSIONAL ENGINEER R.N. SEYMOUR SIGNATURE PROVINCE OF NEWFOUNDLAND	Electrical
	Mechanical
	Civil
	Protection & Control
	Transmission & Distribution
	Telecontrol
	System Planning

Gas Generator Engine Refurbishments

Hardwoods and Stephenville

May 2016

newfoundland labrador hydro
a nalcor energy company

SUMMARY

On February 8, 2016, a gas generator engine failed at the Hardwoods Gas Turbine Plant (Hardwoods). On March 26, 2016, another gas generator failed at the Stephenville Gas Turbine Plant (Stephenville). Both failed engines have been removed from service and cannot be operated. As an interim measure, a leased spare engine (19 MW) was installed at Hardwoods on February 14, 2016 to restore a portion of its capability for the winter of 2016. The Stephenville engine has not been replaced.

The availability and reliability of the Hardwoods and Stephenville plants is critical to ensure voltage regulation of the Island Interconnected System (IIS). In addition, both facilities are important for the generation of peak and emergency power, particularly during the winter. If these engines are not replaced, the power generation capacity of each plant is reduced by 50% (without the leased engine). The capacity of the synchronous condensing start-up system is also reduced by 50%. To restore operational reliability of the gas turbine plants for the IIS, both engines need to be sent to a specialty repair facility for refurbishment.

The Hardwoods engine experienced a failure resulting in damage to the outer casing and turbine sections of the engine. A public tender will be issued and awarded for refurbishment of that engine.

The Stephenville engine experienced a suspected bearing failure in the low pressure compressor section of the engine and failed before its warranty period. The engine has to be returned to the service shop that last refurbished the engine for disassembly and inspection to determine cause of failure. Hydro will be engaging a third party consultant to provide Owner’s oversight during this process.

It is anticipated that both engines will be refurbished and returned to service by November 2016 for winter readiness, with the first available engine installed in Hardwoods.

An analysis of each engine failure will be completed as part of the proposed project. It is anticipated that this will be completed by August 2016.

The budget estimate for this project is $3,047,100 and includes all refurbishment costs for both engines. Pending the results of the investigation to determine the cause of the Stephenville failure, some costs associated with the engine may be recovered under warranty.

TABLE OF CONTENTS

1 INTRODUCTION

Newfoundland and Labrador Hydro (Hydro) owns and operates three gas turbine plants as part of the Island Interconnected System (IIS). The Stephenville Gas Turbine Plant (Stephenville) was commissioned in 1975 and is located in the town of Stephenville. The Hardwoods Gas Turbine Plant (Hardwoods) is located in the west end of St. John's and was commissioned in 1976. The Holyrood Gas Turbine Plant (Holyrood) is located at the Holyrood Thermal Generating Station and was commissioned in 2015.

The Hardwoods and Stephenville plants operate in either generation mode to meet peak and emergency power requirements or synchronous condenser mode to provide voltage support to the IIS. The IIS experiences constant voltage fluctuations that result from changes in the supply and demand of electricity, requiring voltage correction to maintain proper levels. System voltage is managed, in part, by using synchronous condensing equipment. It stabilizes voltage by acting as a shock absorber in the event that the system experiences a voltage change as a result. During synchronous condensing, the voltage change is limited to no more than five percent below nominal operating levels of 230, 138, or 66 kV. Synchronous condensing is an important function of the Hardwoods and Stephenville gas turbine plants. All three of Hydro's gas turbine plants provided significant generation to the IIS in 2016 to support reliable customer service.

The Hardwoods and Stephenville plants each include major mechanical components that consist of two gas generator engines (A and B), two power turbines (A and B), an alternator (see Figures 1 and 2), and auxiliaries such as lube oil, fuel, electrical and control systems. Structures such as buildings, equipment enclosures and exhaust stacks comprise the balance of plant.

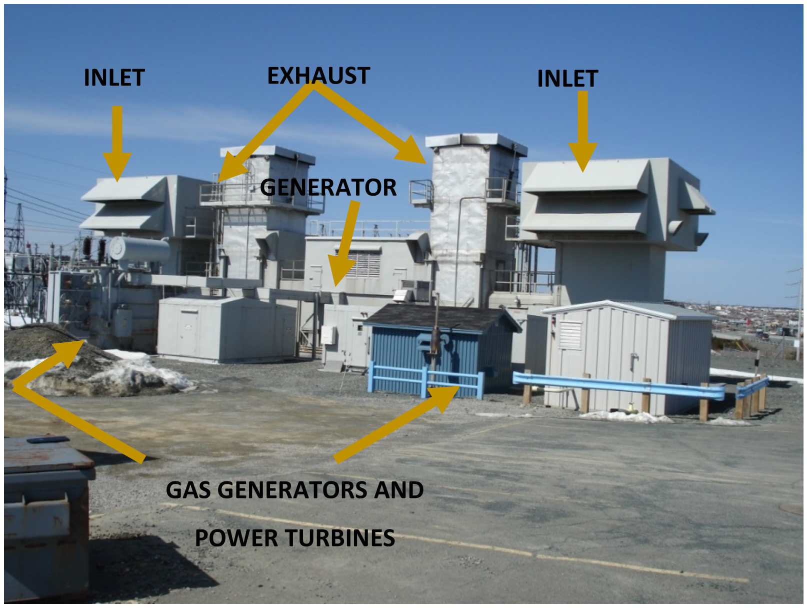


Figure 1: Hardwoods Gas Turbine Plant

Figure 2: Stephenville Gas Turbine Plant

No. 2 fuel oil powers the gas generator engines, which produces compressed hot gases that feed into power turbines causing them to rotate. Each power turbine is connected to the alternator through a clutch. When the alternator reaches its required turning speed, it can perform as either an electricity generator or synchronous condenser. When the alternator operates in generation mode, at least one of the gas generator engines has to operate continuously in order for the alternator to produce power. If two engines are operating, load must be balanced across each. Therefore, if two engines are operating, the total maximum plant output can only be twice that of the smallest unit. When the alternator operates in synchronous condensing mode, only one gas generator is required for a short period of time to start the alternator rotation and get it up to the proper speed. At that point it can operate without the gas generator, which is then shut down.

On February 8, 2016, Hardwoods End A engine, serial number 202205, failed. The preliminary investigation indicated that a combustion can failed causing internal damage to the housing and turbine sections of the engine. The engine was removed from the plant and replaced, on an interim basis, with a leased spare unit provided by Alba Power Ltd. The leased unit is of smaller generation capacity (19MW vs 25MW) than the one being replaced, but fit the installation berth and was readily available for the quickest in-service date during the winter period. The cost of the leased unit is $4,000 per week plus $42 for each hour of operation.

On March 26, 2016, Stephenville End A engine, serial number 202204, also failed. Preliminary investigation suggests that a bearing in the low pressure section of the engine failed and caused other internal damage. Further details will be available after engine removal and analysis are completed. The Stephenville engine is not operational and has not been replaced.

2 PROJECT DESCRIPTION

The scope of this project is to refurbish two failed gas generator engines, one from each of the Hardwoods and Stephenville plants which suffered damage in February and March 2016, respectively.

The scope of work for this project includes the following:

1. Remove and transport Hardwoods End A engine, serial number 202205, to a service facility for disassembly, inspection and refurbishment. The service facility will be determined by public tender;
2. Remove and transport Stephenville End A engine, serial number 202204, to the Alba Power Ltd. service facility for disassembly, warranty investigation and refurbishment;
3. Performance test the two refurbished engines at the respective service facilities;
4. Return transport, installation and commissioning of the two engines; and
5. Independent third party technical oversight of the Stephenville engine at the Alba Power Ltd. service facility on behalf of Hydro to determine cause of failure.

In addition, an analysis of each engine failure will be completed. It is anticipated that the findings of this analysis will be available by August 2016.

This project will be completed by a combination of internal and contracted labour. Installation and commissioning will take place during a planned outage. It is anticipated that both engines will be refurbished and installed by November 2016 for winter readiness, with the first available engine installed in Hardwoods.

3 JUSTIFICATION

The availability and reliability of the Hardwoods and Stephenville plants is critical to ensure voltage regulation of the IIS. In addition, both facilities are important for the generation of peak and emergency power.

More specifically, Hardwoods and Stephenville provide several critical functions on the IIS:

- In synchronous condenser mode, both plants provide reactive voltage support for the major load centers on the island of Newfoundland;
- Both plants are a part of the island system reserve capacity and thus provide power under system peaking and emergency/contingency conditions;
- Hardwoods provides power and reactive output to enable the reliable supply of power to the Avalon Peninsula, which is heavily reliant on the transfer of power over transmission lines from off the Avalon Peninsula, as well as the production of power from the Holyrood Thermal Generating Station. This unit provides a critical backup in the event of a contingency such as the loss of a Holyrood generating unit or loss of a major transmission line into the area;
- Both plants are a part of the contingency plan for the reliable supply of power to the island of Newfoundland; and
- Both plants are also used to facilitate planned generation outages. In addition, Hardwoods is used to facilitate planned transmission outages on the Avalon Peninsula.

To start the plants for synchronous condensing duty, one engine is required to operate for a short period of time. Having two operational engines available provides redundancy for the start-up system. Having one engine out of service eliminates this redundancy and thereby reduces system reliability.

Each gas turbine plant can produce up to 25 MW with one engine operating and 50 MW with both operating. With one engine out of service, generation capacity at each plant is reduced to 25 MW. The out of service engine at Hardwoods was replaced in February 2016 with a leased engine (19 MW). At present the other engine (25 MW) has to be operated at the same output as the leased engine (max 19 MW) to balance the two engines. This provides maximum plant generation capacity at Hardwoods of 38 MW.

3.1 Existing System

The Hardwoods and Stephenville gas turbine plants have two identical drive ends. Each end can generate power up to 25 MW. To differentiate one drive end from the other, the naming convention of End A and End B is used. Each drive end consists of one Rolls-Royce Olympus C gas generator engine (Figure 3) and one Curtiss-Wright power turbine. The gas generator engines are identical and interchangeable between Hardwoods and Stephenville.

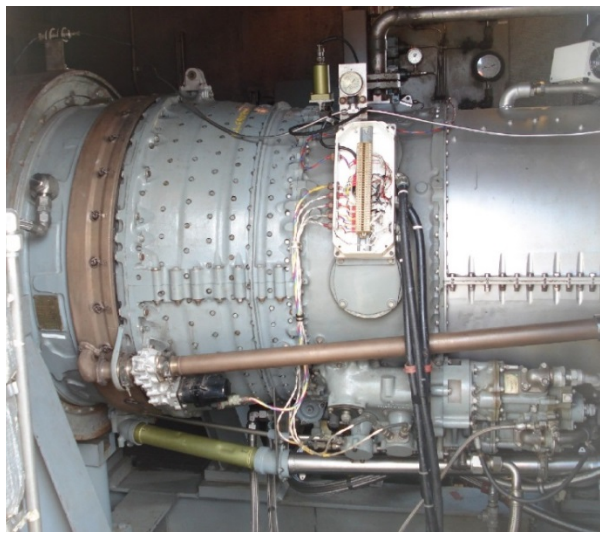


Figure 3: Gas Turbine Engine

At each plant, one Brush generator is shared between the two drive ends. Each drive end is coupled to the alternator by a clutch. Auxiliary systems, critical to the operation of each gas turbine plant, include inlet air systems, fuel oil system, electrical system, and control and instrumentation systems. Buildings and structures on site include exhaust stacks, inlet air intakes, control building, fuel unloading building, fuel forwarding building, auxiliary module building, maintenance and parts storage building, high voltage switchgear building, and emergency backup diesel generator building**.**

Recent major work and upgrades to the Hardwoods and Stephenville gas turbines are provided in Tables 1 and 2.

Table 1: Major Work or Upgrades – Hardwoods

Year	Item	Cost ($000)
2015	**Engine 202224 Overhaul**	**1,252**
2013	**Alternator Replacement Project**	**7,058**
2009-2013	**Plant Life Extension Program**	**3,493**

Table 2: Major Work or Upgrades - Stephenville

Year	Item	Cost ($000)
2014-2016B	**Plant Life Extension Program**	**8,175**
2012-2013	**Alternator Rewind**	**4,135**
2010-2011	**Replacement of Alternator Glycol Cooler**	**861**

3.2 Operating Experience

The Hardwoods and Stephenville plants have been in service for approximately 40 years. Stephenville End A engine, serial no. 202204, was overhauled in 2014 due to age. Hardwoods End A engine, serial no. 202205, was overhauled in 2010 as a result of turbine blade damage.

Tables 3 and 4 provide the generation hours and synchronous condensing hours for Hardwoods and Stephenville from 2011 up to and including April 2016.

Table 3: Hardwoods Gas Turbine Operating Hours 2011 to 2015

Year	Total Operating Hours	Peaking/Emergency Hours	Synchronous Condenser Hours	Available Hours
2016[1]	2,750	624	2,126	2,893
2015	6,036	410	5,626	7,081
2014	6,121	355	5,767	6,502
2013	156	81	75	6,604
2012	3,893	103	3,790	8,259
2011	3,226	38	3,187	8,115

Table 4: Stephenville Gas Turbine Operating Hours 2011 to 2015

Year	Total Operating Hours	Peaking/Emergency Hours	Synchronous Condenser Hours	Available Hours
2016[2]	2,048	227	1,821	2,900
2015	4,984	236	4,748	5,875
2014	6,853	381	6,472	7,043
2013	4,235	66	4,169	4,500
2012	0	0	0	0
2011	8,109	13	8,096	8,438

The following is the timeline of events for each engine from the time of the incident to the date of application to the Board of Public Utilities (Board).

Engine 202205, Hardwoods:

Failure:	February 8, 2016
Initial investigation by Hydro:	February 8/9, 2016
Alba Power engagement:	February 8, 2016
Alba Power representative on site:	February 11, 2016
Installation of replacement engine:	February 14, 2016

[1] From January 1 to April 30
[2] From January 1 to April 30

Alba Power representative inspection completed:	February 18, 2016
Submission to Board:	May, 2016

Engine 202204 Stephenville:

Failure:	March 26, 2016
Initial investigation by Hydro:	March 26/27, 2016
Alba Power engagement:	March 27, 2016
Alba Power representative on site:	March 30, 2016
Alba Power representative inspection completed:	March 30, 2016
Submission to Board	May, 2016

3.2.1 Reliability Performance

Table 5 provides the five year (2011-2015) average Capability Factor, Utilization Forced Outage Probability (UFOP) and Failure Rate for Hardwoods and Stephenville compared to all of Hydro's gas turbine plants and the latest Canadian Electrical Association (CEA) average (2010 to 2014).

Table 5: Hardwoods and Stephenville Five Year Average (2011-2015) All Causes

Unit	Capability Factor (%)[3]	UFOP (%)[4]	Failure Rate[5]
Hardwoods	75.88	24.82	133.05
Stephenville	42.39	40.10	151.13
All Hydro Gas Turbine Units	70.30	24.83	107.51
CEA (2010-2014)	84.16	9.52	66.60

[3] Capability Factor is defined as unit available time. It is the ratio of the unit's available time to the total number of unit hours.
[4] UFOP is defined as the Utilization Forced Outage Probability. It is the probability that a generation unit will not be available when required. It is used to measure performance of standby units with low operating time such as gas turbines.
[5] Failure Rate is defined as the rate at which the generating unit encounters a forced outage. It is calculated by dividing the number of transitions from an Operating state to a forced outage by the total operating time. It can be greatly influenced by operating time of standby units such as gas turbines.

3.2.2 Legislative or Regulatory Requirements

There are no legislative or regulatory requirements related to this project.

3.2.3 Safety Performance

This project is not expected to affect safety performance.

3.2.4 Environmental Performance

This project is not expected to affect environmental performance.

3.2.5 Industry Experience

Industry experience is not relevant to this project.

3.2.6 Vendor Recommendations

There are no vendor recommendations applicable to this project.

3.2.7 Maintenance or Support Arrangements

Normal routine maintenance work is performed by Hydro. However, gas turbine service companies such as Rolls Wood Group Ltd. and Alba Power Ltd., both located in the United Kingdom, have been contracted in the past to perform visual inspections, on-site specialty maintenance items, and major shop overhauls of gas generator engines. Most recent engine refurbishments were publicly tendered and awarded to Alba Power Ltd.

3.2.8 Maintenance History

Borescope inspections for Hardwoods and Stephenville gas generator engines were completed every two years until 2014. Considering the age and anticipated increased operation of the engines, annual borescope inspections were planned thereafter. The most recent internal inspection was performed on Hardwoods in December 2015 and on Stephenville in November 2015 (see Appendix B). In each case no problematic conditions were observed.

Both engines have received a major refurbishment in the past under approved planned capital plant life extension programs. The Hardwoods engine was last overhauled in 2010. The Stephenville engine was last overhauled in 2014. Hydro expected to operate each of these engines for at least ten years following each refurbishment before another would be required.

The five-year operating maintenance history for the gas turbine plants at Hardwoods and Stephenville is provided in Tables 6 and 7.

Table 6: Five-Year Maintenance History - Hardwoods

Year	Preventive Maintenance ($000)	Corrective Maintenance ($000)	Total Maintenance ($000)
2015	45	543	588
2014	65	657	722
2013	13	65	78
2012	22	116	138
2011	43	104	147

Table 7: Five-Year Maintenance History - Stephenville

Year	Preventive Maintenance ($000)	Corrective Maintenance ($000)	Total Maintenance ($000)
2015	30	274	304
2014	21	562	583
2013	39	191	230
2012	12	105	117
2011	26	89	115

3.2.9 Historical Information

Hardwoods has been in service for 40 years providing synchronous condensing and generation capability to the IIS. Stephenville has been in service for 41 years providing similar functions.

Plant life extension upgrade programs began at Hardwoods in 2009 and at Stephenville in 2014.

3.2.10 Anticipated Useful Life

A typical gas turbine plant has an average useful life of 35 years based on primary operation for base load power generation. The Hardwoods and Stephenville plants have exceeded this service life because they have operated primarily as synchronous condensers. The result has been relatively few operating hours on each plant while running in base load power generation. Hydro has confirmed with specialized vendors that they will continue to service the engines for the foreseeable future. A conservative estimate is that each engine will have at least 10 years of service life remaining after engine refurbishment.

3.3 Forecast Customer Growth

This project is not required to accommodate customer growth.

3.4 Development of Alternatives

A number of alternatives were considered before one was selected for this proposal. The following provides commentary on those alternatives with particular consideration to cost, reliability and the greatest potential to achieve in-service status by November 2016 to meet winter availability requirements.

<u>Alternative No. 1 – Refurbish the existing engines:</u>

This alternative includes removing the failed engines and sending them to a specialty service facility for disassembly, inspection, refurbishment, and performance testing. They would then be returned to the generation plants, installed and commissioned. This alternative has a budget of $3.05 million and both engines would be returned to service by the November 2016 target date for winter readiness. This is the preferred option.

Alternative No. 2 – Replace the engines with leased engines:

This alternative would replace the failed engines with leased engines of the same capacity. Hydro has been unable to identify new or used engines on the market with the same capacity that are readily available for installation. It is anticipated that other used engines could be located but would need to be refurbished prior to installation. Hydro submits that the reliability of these leased, refurbished engines, would be equal to Hydro's own refurbished engines. However, there could be unexpected fitting problems installing the engines in the existing berths. Such problems would increase the risk of not meeting the November 2016 in-service date for winter readiness. It is estimated that the annual lease cost would be $300,000 plus an estimated $40,000 annually for hourly operating charges for Hardwoods and $15,000 annually for hourly operating charges for Stephenville. Transportation and installation costs would be in additional to the lease amounts. It is estimated that the leasing costs alone for this alternative would equal the total capital cost of Alternative 1 in less than two and a half years with the lease costs continuing thereafter.

Alternative No. 3 – Replace the engines with new engines:

There are no newly manufactured engines available on the market that can be readily installed in the existing engine berths. Modifications to the existing berths would be required along with auxiliary support systems. This would also be a prototype design with no history of reliable service. A high level project budget estimate is in excess of $10 million and the project cannot be completed by November 2016.

With consideration to the alternatives discussed above, Alternative No. 1 is proposed as the least cost viable option.

4 CONCLUSION

In February 2016, Hardwoods End A engine, serial number 202205 failed. In March 2016, Stephenville End A engine, serial number 202204 also failed. Both engines have been removed from service and are no longer operational. The availability and reliability of the

Hardwoods and Stephenville plants is critical to ensure voltage regulation of the IIS, generation of peak power, emergency power and planned generation or transmission outages. Without refurbishing these engines, power generation capacity of each plant and reliability of the synchronous condensing start-up system are reduced. As such, both engines are required to provide reliability to the IIS.

This project proposes to refurbish the two failed gas generator engines in order to restore the generation capacity and reliability of the gas turbine plants and provide continued reliability support to the IIS.

Budget Estimate

Hydro consulted the successful bidder on previous tenders, Alba Power Ltd., to determine a reasonable budget estimate. As per Table 8, the project budget to refurbish and reinstall both engines is estimated at $3,047,100, including a contingency for unanticipated items.

Table 8: Project Budget Estimate

Project Cost: *($ x1,000)*	**2016**	**2017**	**Beyond**	**Total**
Material Supply	1.0	0.0	0.0	1.0
Labour	160.6	0.0	0.0	160.6
Consultant	200.0	0.0	0.0	200.0
Contract Work	2,120.0	0.0	0.0	2,120.0
Other Direct Costs	46.7	0.0	0.0	46.7
Interest and Escalation	13.1	0.0	0.0	13.1
Contingency	505.7	0.0	0.0	505.7
TOTAL	**3,047.1**	**0.0**	**0.0**	**3,047.1**

The budget for this project provides for the full cost of completing two engine overhauls. It is estimated that 55% of the total project cost is associated with the Stephenville work and 45% with the Hardwoods work. It should be noted that the Stephenville engine failed within the warranty period from a previous refurbishment in 2014. A copy of the warranty is provided in Appendix A. This project will also investigate the cause of the recent failure to determine if there is any cost recovery under warranty.

A review of Hydro's insurance policy determined that these engine refurbishment costs are not recoverable, as the deducible for property damage is $10M.

Project Schedule

The anticipated project schedule is provided in Table 9.

Table 9: Project Schedule

Activity		**Start Date**	**End Date**
	Stephenville Engine 202204		
Planning	Transport engine to Alba for disassembly and warranty inspection.	May 2016	June 2016
	RFP for third party warranty inspection.	May 2016	May 2016
Procurement	Disassembly and warranty evaluation.	June 2016	July 2016
	Refurbish and bench test.	July 2016	Sept 2016
	Transport to HWD and install.	Sept 2016	Oct 2016
Commissioning	Commission and in-service.	Oct 2016	Oct 2016
	Hardwoods Engine 202205		
Planning	Prepare tender for engine refurbishment and public tender.	May 2016	May 2016
Procurement	Tender evaluation and award.	Jun 2016	Jun 2016
	Transport to repair facility, refurbish and bench test.	July 2016	Oct 2016
	Transport to SVL and install.	Oct 2016	Nov 2016
Commissioning	Commission and in-service.	Nov 2016	Nov 2016
Project Closeout	Prepare post implementation review report and closeout documents.	Dec 2016	Dec 2016

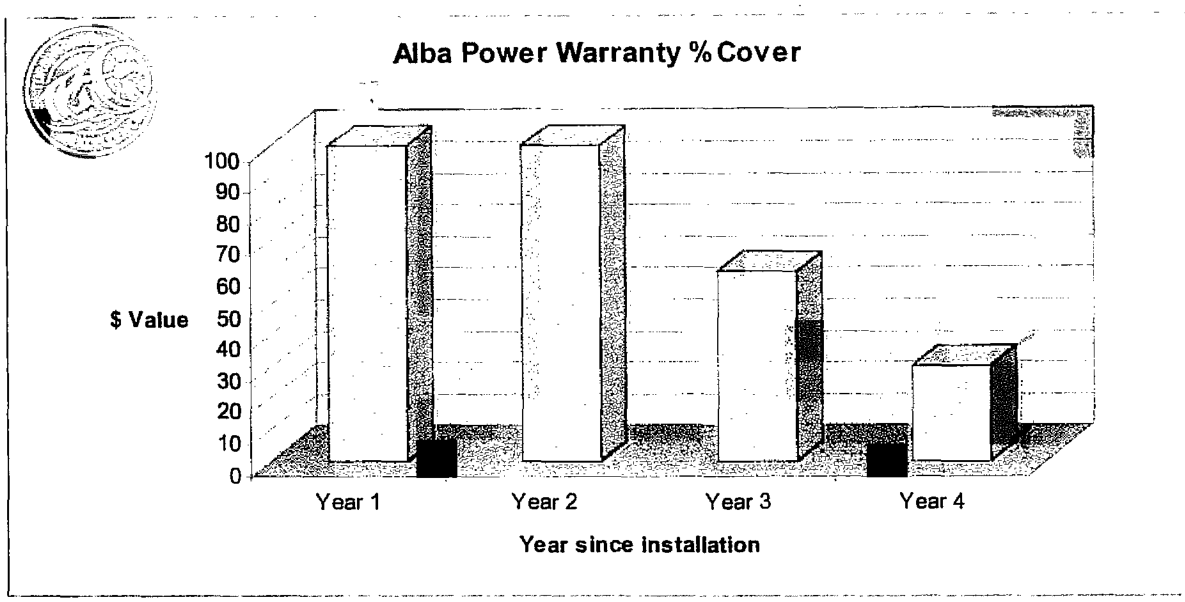
The schedule is aggressive and provides for refurbished engines to be in service by the end of November 2016 for winter readiness. To facilitate that schedule, Hydro will be undertaking planning actions in May and early June while regulatory review takes place.

It is anticipated that the Stephenville engine will be refurbished and ready for installation earlier then the Hardwoods engine. Restoration of the Hardwoods plant is first priority, for that reason, Hydro plans on installing the first available engine at that plant.

Extended Warranty

Appendix A
Page 1 of 1

Alba Power has pleasure in offering coverage for 4 years as below, all included within fixed price proposal.



Benefits of extended warranty

- Piece of mind throughout operation
- Access to Alba Power Lease units if required
- Manpower pool access for remedial works if required
- Spare parts exchange access

Normal client responsibilities for maintenance and operation apply throughout

your power
is our priority

Hot End Borescope Inspection Report For Gas Turbine 202205

newfoundland labrador
hydro
a nalcor energy company

Customer: Newfoundland Hydro Hardwoods

Date: 3rd December 2015

Project Number: Alba 4927

Alba Power Ltd
Tel: (44) 01569 730088
Fax: (44) 01569 730099
sales@albapower.com
www.albapower.com

Quality Certification
ISO 9001:2008
ISO 14001:2004
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Note:

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1 Introduction

Mr Colin Smith was mobilised to Hardwoods, St Johns, Newfoundland Hydro power station to carry out the hot end borescope inspection and health check survey on the Olympus Gas Turbine serial number 202205.

2 Purpose

The purpose of the borescope and hot end inspection is to determine the internal and external condition of Olympus gas turbine 202205. A general inspection was carried out on the Olympus gas turbine and air intake plenum.

The following report outlines the associated inspections and actions carried out during the time on site.

3 Onsite Personnel

Colin Smith (Alba Power)

4 Daily Report

4.1 Tuesday 1st December.

Travel from Stephenville to St Johns Newfoundland, could not get the outage to carry out borescope inspection.

4.2 Wednesday 2nd December.

Due to power outage at Holyrood site Hardwoods site could not allow outage to perform borescope inspection.

4.3 Thursday 3rd December.

Arrived on site. Tail board talk carried out. Gas Turbine 202205 was isolated and Fuel Nozzles 2,4,6 and 8 removed, and a borescopic inspection of the rear stages of the HP compressor , snouts, combustion chambers, HP NGVs and LP NGVs was carried out. G lab vent duct was removed and borescope inspection carried out inside turbine support housing number 7 bearing housing assembly and HP shaft seal.

5 Borescope Report

LP Compressor

Stage 1 to 5 Rotor blades and stator vanes are deemed in a serviceable condition.

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Intermediate Casing

A limited inspection of the inner starter and oil pump drives indicated they were in a serviceable condition with no visual defects or damage noted on this unit.

HP Compressor

The 1st stage HP rotor blades are in good condition with no visual defects or damage noted; they are in a serviceable condition.

The 7th stage HP rotor blades and stator vanes are in good condition with no visual defects or damage noted and the coatings look to be in a good condition and they are considered to be in a serviceable condition.

Combustion Chambers and snouts

The snouts exhibit typical carbon deposits around the burner entry location, there is also evidence of a build-up of carbon inside the combustion chambers, there was no visual signs of any cracks within the combustion chambers of this unit.

The No6 combustion chamber interconnector has a small crack but is within limits.

Fuel nozzles

The fuel nozzles exhibit typical carbon deposit on the heads, no other defects or damage was noted.

HP& LP Nozzle Guide Vanes

The HP nozzle guide vanes and LP nozzle guide vanes were noted as having no visual damage; however they did show some signs of coating loss and carbon built up. All are considered to be in a serviceable condition.

HP Turbine Blades

The HP turbine blades were noted as having no visual damage or defects but showed some signs of coating loss. All are considered to be in a serviceable condition.

Magnetic Chip Detectors

All found to be clear and free from any debris.

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6 Olympus Gas Turbine 202205 Images

	
Pipe Connection	Slight oil leak at number 7bearing housing
	
Rear of HP Compressor	HP NGV's

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Carbon build up on Fuel Nozzle	Entry Snout
	
Carbon deposits	Crack at No6 Interconnector
	
LP Compressor early stages	HP compressor

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	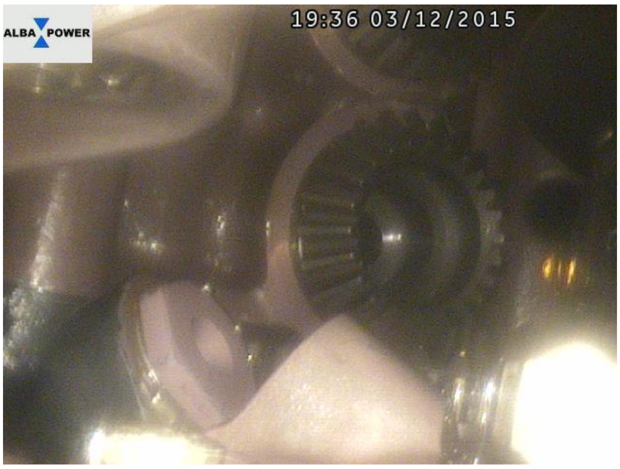
Drive gears Intermediate Case	Fuel pump drive gears

7 Summary

The Olympus 202205 gas turbine was found to be in a serviceable condition.

8 Recommendations

The Gas Turbine should be regularly serviced to maintain a good level of engine performance.

On site personnel:	Colin Smith	Date:	1st December 3rd December
Report compiled by:	Colin Smith	Date:	7th December 2015
Reviewed by:	Bruce Proctor	Date:	8th December 2015

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9 Customer Acceptance

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10 Customer sign off sheet

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Customer Acceptance Sign Off Sheet

ALBA Job No: 4927

Description of Works: Health Check & Borescope Inspection.

Site: Newfoundland Hydro

Customer: Newfoundland Hydro

Designate: Olympus

Manufacture: Rolls Royce

Eng. Serial No:

Having witnessed the installation and commissioning of Rolls Royce Olympus S/N [illegible] gas turbine, I the under signed, am satisfied with the work carried out and that it complies with the works being completed within the boundaries of the contract.

Signed:
Print:
Position: Operator
Date: 2015/12/03
For: Newfoundland Hydro

Signed:
Print: COLIN SMITH
Position: FIELD SERVICE TECH
Date: 3/12/15
For: Alba Power Ltd

Customer: Newfoundland Hydro
APFS 034
www.albapower.com
sales@albapower.com
Page24
Date: 26/07/15

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Hot End Borescope Inspection Report For Gas Turbine 202204

Customer: Newfoundland Hydro Stephenville

Date: 30th November 2015

Project Number: Alba 4927

Alba Power Ltd
Tel: (44) 01569 730088
Fax: (44) 01569 730099
sales@albapower.com
www.albapower.com

Quality Certification
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1 Introduction

Mr Colin Smith was mobilised to Stephenville Newfoundland Hydro power station to carry out the hot end borescope inspection and health check survey on the Olympus Gas Turbine serial number 202204.

2 Purpose

The purpose of the borescope and hot end inspection is to determine the internal and external condition of Olympus gas turbine 202204. A general inspection was carried out on the Olympus gas turbine and air intake plenum.

The following report outlines the associated inspections and actions carried out during the time on site.

3 Onsite Personnel

Colin Smith (Alba Power)

4 Daily Report

4.1 Sunday 29th November.

Travelled to Stephenville Newfoundland

4.2 Monday 30th November.

An induction for safety regulations of site was conducted between 08.30am – 09.30am.

Tail board talk was carried out by Ray Rowe (Newfoundland Hydro Operator) . Set A 202204 was isolated and fuel nozzles, 2, 4, 6 and 8 were removed and a borescopic inspection of the rear stages of the HP compressor, snouts, combustion chambers, HP NGVs and LP NGVs was carried out.

5 Borescope Report

LP Compressor

Stage 1 to 5 Rotor blades were found to be in a serviceable condition.

HP Compressor

Stages 1 to 7 HP rotor blades are in good condition with no visual defects or damage noted; they are in a serviceable condition.

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Combustion Chambers and snouts

The snouts exhibit typical carbon deposits around the burner entry location, there is also evidence of a build-up of carbon inside the combustion chambers, there was no visual signs of any cracks within the combustion chambers of this unit.

Fuel nozzles

The fuel nozzles exhibit typical carbon deposits with no other defects or damage noted.
.

HP& LP Nozzle Guide Vanes

The HP nozzle guide vanes and LP nozzle guide vanes were noted as having no visual damage; however they did show some signs of coating loss and carbon built up. All are considered to be in a serviceable condition.

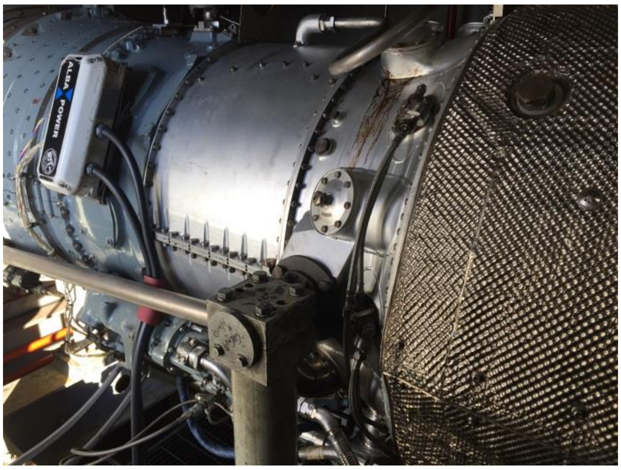
HP Turbine Blades

The HP turbine blades were noted as having no visual damage or defects and are considered to be in a serviceable condition.

Magnetic Chip Detectors

No debris was found on any of the chip detectors.

6 Olympus Gas Turbine 202204 Images

	
Olympus 202204	Olympus 202204 exterior condition port side

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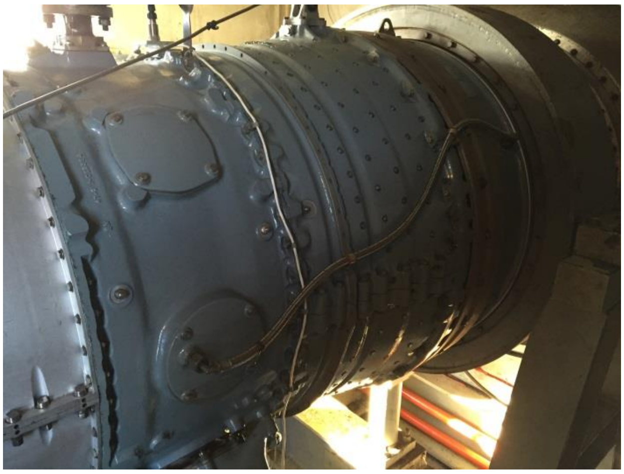
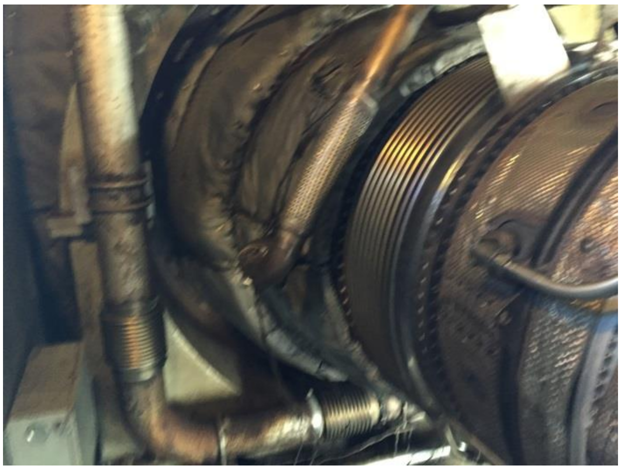


Olympus 202204 exterior condition starboard



Olympus 202204 exterior condition

Rear stages of HP compressor

Carbon build up on base of combustion can

HP NGVs and turbine blades

Carbon build up on combustion chamber

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Combustion chamber exterior

HP NGV,s

Combustion chamber side wall

LP compressor rear

Condition of snouts

Turbine entry duct

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7 Summary

The Olympus Gas Turbine 202204 was found to be in a serviceable condition.

8 Recommendations

The Gas Turbine should be regularly serviced to maintain a good level of engine performance.

On site personnel:	Colin Smith	Date:	29th Nov –30th Nov 2015
Report compiled by:	Colin Smith	Date:	7th December 2015
Reviewed by:	Bruce Proctor	Date:	8th December 2015

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9 Customer Acceptance

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9 Customer sign off sheet

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Customer Acceptance Sign Off Sheet

ALBA Job No: 4927

Description of Works: Health Check & Borescope Inspection.

Site:

Customer: Newfoundland Hydro

Designate: Olympus 202223 + 202204

Manufacture: Rolls Royce

Eng. Serial No:
202223

Having witnessed the installation and commissioning of Rolls Royce Olympus S/N 202204 gas turbine, I the under signed, am satisfied with the work carried out and that it complies with the works being completed within the boundaries of the contract.

Signed:
Print:
Position: Operator
Date: 2015/12/03
For: Newfoundland Hydro

Signed:
Print: C SMITH
Position: FIELD SERVICE TECH
Date: 3/12/15
For: Alba Power Ltd

Customer: Newfoundland Hydro
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sales@albapower.com
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Date: 26/07/15

REGISTERED PROFESSIONAL ENGINEER R.N. SEYMOUR SIGNATURE PROVINCE OF NEWFOUNDLAND	Electrical
	Mechanical
	Civil
	Protection & Control
	Transmission & Distribution
	Telecontrol
	System Planning

Increase Fuel and Water Treatment System Capacity

Holyrood Gas Turbine

July 2017

A Report to the Board of Commissioners of Public Utilities

newfoundland labrador hydro
a nalcor energy company

Summary

The Holyrood Gas Turbine, located on the Holyrood Thermal Generating Station (Holyrood) site, is a 123.5 MW gas turbine generating unit that was placed in service in February 2015. Since that time, the gas turbine has been operated more frequently and for longer durations for system reliability than was foreseen when the engineering for its installation was undertaken. Hydro anticipates that there may be emergency situations requiring frequent or long periods of generation from the gas turbine in the future. To facilitate reliable operation of the gas turbine for these situations, this project proposes an increase in the on-site fuel storage capacity from 2.5 million litres to 5.0 million litres and the capacity of the demineralized water production from 380 litres per minute to 570 litres per minute.

This project has an estimated cost of $11,842,600. The additional demineralized water capacity and fuel storage will be in-service in 2018. The final painting of the fuel tanks installed under this project will be completed in 2019.

Table of Contents

1.0 Introduction

The 123.5 MW Holyrood gas turbine, located at the Holyrood Thermal Generating Station site (Holyrood), was installed to provide:

- Additional long term generation capacity for the Island Interconnected System (IIS); and
- Additional generation capacity on the Avalon Peninsula, to mitigate local generation supply and transmission contingencies.

During engineering and prior to the gas turbine's installation, future generating levels were forecasted and supporting systems, including the fuel storage and the nitrogen oxide (NO_x) emission control water treatment systems were sized according to that forecast.

Since being placed in service, the gas turbine has been utilized more frequently and for longer durations than was foreseen during engineering design of the unit. This additional generation is a result of:

- The requirement to provide generation to obtain appropriate levels of spinning reserve on the IIS due to forecasted system loads and/or forecasted unavailability of other generators, e.g. outages, both planned and unplanned, at the Holyrood Thermal Generating Station[1];
- Facilitation of continuous generation supply in the event of a major generating unit outage or transmission line loss;
- Facilitation of planned generation and Avalon Peninsula transmission outages;
- Operation as standby generation during circumstances, in which a "single worst Avalon contingency event" could cause sustained customer interruptions; and
- The need to provide additional generation to offset hydraulic generation and ensure adequate availability of water-based generation when drier weather conditions and

[1] Technical details of the failures are provided in recent applications to the Board.
- Replacement of the lower reheater boiler tubes on Units 1 and 2, and additional reliability improvements at the Holyrood Thermal Generating Station – 2016 Supplemental Capital Application
- Unit 2 Boiler Tube Replacement at Holyrood Thermal Generating Station – 2016 Allowance for Unforeseen Items
- Unit 1 Boiler Tube Replacement at Holyrood Thermal Generating Station – 2016 Allowance for Unforeseen Items

low precipitation periods occur, such as those experienced in late 2015 and early 2016.

Table 1 provides the forecasted and actual operating hours for the gas turbine from February 2015 to June 2017.

Table 1: Forecasted and Actual Operating Hours – Holyrood Gas Turbine from 2015-2017

Year	Forecasted Annual Running Hours	Actual Running Hours
2015	184	788
2016	294	1,818
2017	529	570 (to June 30, 2017)

With the gas turbine providing this additional generation, shortcomings were experienced in the existing capacity of the fuel storage facility, as well as with the water treatment system that supplies water for nitrogen oxide (NO_x) emission control.

The electrical system operating requirements and equipment conditions could result in high levels of generation to be required in the future.

2.0 Project Description

2.1 Fuel Storage System

The project proposes the expansion of the fuel storage system by adding two 1.25 million litre tanks. Activities include:

1) Civil site preparation, including containment dyke with liner and tank foundation; Construction of steel storage tanks;
2) Installation of fire protection system; and
3) Installation of mechanical and electrical systems, and connections to the existing pipe and control systems.

The estimated cost of this portion of the project is $ 10,895,900. The tanks will be placed in service in 2018 with the final exterior painting of the tanks scheduled for completion in 2019.

2.2 Water Treatment System

This project also proposes the expansion of the demineralized water capacity from 380 litres per minute to 570 litres per minute. Activities include:

1. Addition of structural steel, grating, handrails, and stairs;
2. Installation of additional demineralized water treatment equipment; and
3. Installation of mechanical and electrical installations, and connection to the existing pipe and control systems;

The estimated cost of this portion of the project is $946,700 and the additional water treatment equipment will be placed in-service in 2018.

3.0 Justification

3.1 Fuel Storage System

The fuel for the Holyrood gas turbine is stored in two 1.25 million litre storage tanks. Figure 1 shows the facility and the proposed expansion location.

Figure 1: Existing Storage tanks, Off-Loading Facility, and Proposed Location of new tanks.

A consequence of the requirement for increased generation is the requirement for increased reliance on sustained higher daily fuel deliveries. While required deliveries to date have been achieved, the following risks could impact future deliveries:

1. <u>Fuel Production Problems:</u> The refinery supplying the fuel could experience production limitations. In March 2015, the fuel supplier was unable to provide product for a period of seven days.
2. <u>Poor Weather and Road Conditions:</u> Weather conditions could impose road conditions such that fuel deliveries could be impacted. In 2016, weather conditions caused delivery trucks to be stuck, thus causing delivery delays.
3. <u>Truck and Driver Availability:</u> The required number of fuel delivery trucks and drivers may not be available in the Province to meet unscheduled fuel deliveries requested on short notice. In 2016, due to driver unavailability, deliveries were delayed to allow for driver rest periods.
4. <u>Unloading Issues:</u> Often, multiple trucks are waiting at the storage area as shown in Figure 2. As only one truck can be unloaded at a time, if a truck broke down obstructing the offloading station, deliveries would be delayed.

Figure 2: Fuel Trucks Waiting to be Off Loaded

To mitigate these risks, the following alternatives to increase fuel storage capacity were considered:

1. Construct 2 additional 1.25 million litre storage tanks (Capital cost of $10.9 million).
2. Refurbish an existing Holyrood No. 6 oil tank (Capital cost of $20 million).
3. Modify the existing gas turbine tanks to provide additional storage.

Alternative 2 was not selected because of its higher capital cost. Alternative 3 was eliminated because analysis showed that modification of an existing oil tank would only provide an additional 0.5 million litres of storage.

To increase gas turbine fuel storage, Hydro has determined that it needs to increase its fuel storage capacity to 5 million litres. When the new tanks are full, the additional on-site storage will allow, without any deliveries, the gas turbine to generate at 100% capacity for 5 days. With continued historical normal daily fuel deliveries of 400,000 litres and assuming that the expanded storage facility is full at the start of a period, the gas turbine will be able to generate at 100% capacity for 10 days.

3.2 Water Treatment System

The gas turbine utilizes demineralized water during the combustion process to reduce nitrous oxide (NOx) emissions released to the environment. The existing water treatment system, through a process of reverse osmosis, produces demineralized water at a rate of 380 litres per minute. Figure 3 shows the current facility and the locations for the equipment to be added above the Reverse Osmosis Skid.

Figure 3: Demineralized Water System

In the past, periods of increased generation resulted in the demineralized water requirement exceeding the capacity of the treatment system. Table 2 provides the date, time, and duration for each of the interruptions in emission control as a result of the inability of the demineralized water treatment system to maintain the required water supply.

Table 2: Interruptions in Service (2016)

Start		Finish		Duration
Date	Time	Date	Time	HH:MM
6-Jan	20:01	7-Jan	0:37	4:36
9-Jan	14:15	9-Jan	23:15	9:00
13-Jan	20:04	14-Jan	6:36	10:32
22-Jan	11:35	23-Jan	4:22	17:47
23-Jan	22:20	24-Jan	16:28	18:08
26-Jan	17:19	27-Jan	11:55	18:36
3-Feb	9:55	4-Feb	5:10	19:15
8-Feb	1:37	8-Feb	23:23	21:46
9-Feb	17:00	9-Feb	10:09	17:09
15-Feb	10:15	15-Feb	16:58	6:43
15-Feb	21:01	16-Feb	19:24	22:23
19-Feb	16:30	20-Feb	10:30	18:00
21-Feb	13:05	22-Feb	7:48	18:43
24-Feb	4:30	24-Feb	15:20	10:50
24-Feb	22:30	25-Feb	22:09	23:39
8-Mar	6:30	8-Mar	7:37	1:07

Generation in these situations is not in compliance with the plant's Certificate of Approval. The gas turbine is operated under Certificate of Approval No. AA14-125602. As per Section 38 of this approval, Hydro shall not operate the 123.5 MW gas turbine unless the NO_x control system associated with the unit is in full operation. To ensure compliance with Section 38, Hydro will expand the capacity of the water treatment system from 380 to 570 litres per minute.

The following alternatives to provide the additional capacity were considered:

1. *Rent a Mobile Water Treatment Trailer to Supplement Existing System* - Based upon gas turbine generating history, the trailer would be required annually, from December to March. The alternative would require modifications to the existing system, costing approximately $368,500 and having reoccurring annual rental and hook-up costs of approximately $82,000.

2. *Install Additional Equipment in Combination with Existing Equipment* - Purchasing and installing additional water treatment equipment to run in combination with the existing equipment has a capital cost of $972,500 and an annual operating cost of $6,250. This alternative had an anticipated life of 34 years.

Using a 34-year study period and Hydro's current long-term weighted average cost of capital and a discount rate of 6.5 percent, it was determined that installing additional equipment in combination with existing equipment results in the least cumulative present worth cost (please refer to Table 3).

Table 3: CBA of Alternatives

Expand Water Treatment System - Holyrood Gas Turbine		
Alternative Comparison ***Cumulative Net Present Value*** ***To The Year*** **2017**		
Alternatives	**Cumulative Net Present Value (CPW)**	**CPW Difference between Alternative and the Least Cost Alternative**
[New Agumented System]	1,226,629	0
[Mobile Trailer]	1,803,897	577,268

An additional benefit of Alternative 2 is that it will provide adequate treated water throughout the year when unforeseen emergency situations require the gas turbine to generate at or near capacity for extended periods.

4.0 Conclusion

Since being placed in service, the Holyrood gas turbine has been operated more frequently and for longer durations than was foreseen during engineering design of the unit. Deficiencies in the existing capacity of the gas turbine fuel storage facility and water treatment system have been experienced and this project is being proposed to ensure that the facility is operated within the terms of its certificate of approval and that a reliable supply of fuel is available for periods of extended operation as may be required.

4.1 Budget Estimate

Table 4: Project Budget Estimate

Project Cost: *($ x1,000)*	2018	2019	Beyond	Total
Material Supply	0.0	0.0	0.0	0.0
Labour	1,059.6	157.9	0.0	1,217.5
Consultant	269.2	0.0	0.0	269.2
Contract Work	5,696.7	2,200.0	0.0	7,896.7
Other Direct Costs	32.2	6.6	0.0	38.8
Interest and Escalation	360.7	175.3	0.0	536.0
Contingency	1,411.5	472.9	0.0	1,884.3
TOTAL	**8,829.9**	**3,012.7**	**0.0**	**11,842.6**

4.2 Project Schedule

Table 5: Project Schedule

Activity		Start Date	End Date
Planning	Engage fuel storage consultant to prepare tender documents.	January 2018	February 2018
	Engage treatment consultant to prepare tender documents.	January 2018	June 2018
Design	Prepare storage tender documents.	March 2018	March 2018
	Prepare treatment tender documents	February 2018	March 2018
Procurement	Tender and award storage supply and installation contracts.	April 2018	
	Tender and award treatment supply and installation contracts.	March 2018	May 2018
Construction	Storage construction	July 2018	December 2018
	Treatment construction	July 2018	July 2018
Commission	Place in service treatment	July 2018	August 2018
	Place in service storage	November 2018	December 2018
Painting	Final exterior painting storage	July 2019	July 2019
Closeout	Project closeout	August 2019	September 2019

REGISTERED PROFESSIONAL ENGINEER MOHAMED KHALIFA SIGNATURE July 21, 2017 DATE NEWFOUNDLAND & LABRADOR	Electrical
	Mechanical
	Civil
	Protection & Control
	Transmission & Distribution
	Telecontrol
	System Planning

Turbine Hot Gas Path Level 2 Inspection and Overhaul

Holyrood Gas Turbine

July 2017

A Report to the Board of Commissioners of Public Utilities

newfoundland labrador
hydro
a nalcor energy company

Summary

Hydro owns and operates a 123.5 MW gas turbine plant, which is located at the Holyrood Thermal Generating Station (Holyrood), approximately 43 kilometers South West of St. John's.

Hydro has incorporated on-going hot gas path inspections and overhauls into its long term plan to maintain reliable operation of the Holyrood gas turbine.

The gas turbine unit manufacturer, Siemens, recommends that a hot gas path inspection and overhaul be completed when the total equivalent starts on the gas turbine reaches 800 (See Appendix A). Hydro anticipates that the Holyrood gas turbine will reach this milestone in 2019.

This proposed project will complete a hot gas path inspection and overhaul on the gas turbine unit. The planning and procurement will be completed in 2018 and the inspection and overhaul will be completed in 2019.

The budget for this project is $11,146,500.

Table of Contents

1.0 Introduction

Hydro owns and operates a 123.5 MW gas turbine plant, which is located at the Holyrood Thermal Generating Station (Holyrood), approximately 43 kilometers South West of St. John’s. The plant was constructed in 2014 and commissioned early in 2015. The plant fulfills several key functions in reliably supplying customer demand requirements as follows:

1. The plant is operated to support spinning reserves on the Island Interconnected System. It provides a critical backup in the event of a contingency, such as the loss of a major generating unit.
2. The plant provides power to the Avalon Peninsula which is heavily reliant on the transfer of power over transmission lines from outside of the Avalon Peninsula, as well as the production of power from the Holyrood Thermal Generating Station. It provides a critical backup in the event of a contingency, such as the loss of a Holyrood unit, or loss of a major transmission line into the area. The plant is also used to facilitate planned generation and Avalon Peninsula transmission outages.

2.0 Project Description

This is a two year project to complete a hot gas path inspection and overhaul of the gas turbine unit located at the Holyrood Gas Turbine Plant. This work includes:

- Replacement of specific hot gas path components identified by the manufacturer in this overhaul;
- Completion of a Level 2 inspection and assessment, which involves visual inspection to identify damages in the hot gas path components and non-destructive examination techniques to find hidden or small cracks that may propagate and lead to in-service failure; and
- If required by the assessment, additional refurbishment or replacement of deteriorated components.

The installation of an access hatch in the powerhouse roof to allow for lifting major components out of the building to a laydown area by the powerhouse during the inspection and overhaul is also included in the scope of work.

3.0 Justification

Hydro has incorporated on-going hot gas path inspections and overhauls into its long term plan to maintain reliable operations of the Holyrood gas turbine. According to Hydro's operational forecast, to avoid exceeding the total equivalent starts criteria, the first hot gas path inspection and overhaul will need to be completed in 2019. The Holyrood Gas Turbine Plant is important to the reliability of power to the Avalon Peninsula and therefore must be properly maintained.

3.1 Existing System

The gas turbine generator can generate 123.5 MW. The generation is accomplished by energy obtained from fuel consumed in the gas turbine unit of the generator. The gas turbine unit has a hot gas path, which consists of the combustion, turbine, and exhaust sections which are shown in Figure 1.

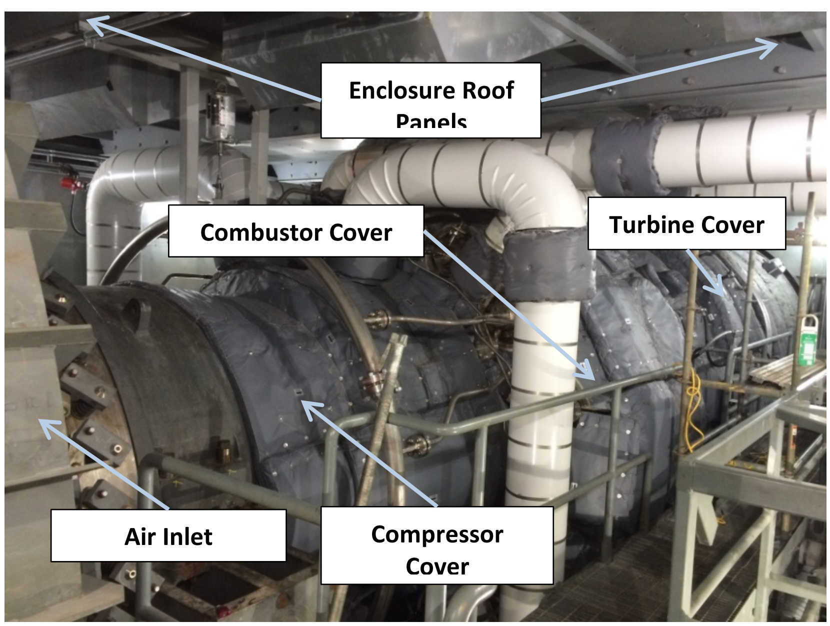

Figure 1: Siemens 501D5A Gas Turbine Unit

The hot gas path is subjected to high temperature and pressure in the combustor and turbine sections. Over time, this high pressure and temperature causes deterioration such as thermal fatigue, cracking, wear, and corrosion of components. This deterioration establishes the requirement to replace specific components, complete Level 2 inspection and assessments and, if required, refurbish or replace additional deteriorated components.

3.2 Operating Experience

The Holyrood gas turbine has been in service since March 2015. A combustor inspection major and overhaul was completed in 2016 when the total equivalent starts approached 400. A combustor inspection overhaul involves removal of all combustor baskets and transition pieces and associated components that are accessible through a manhole on the combustor cover. Components that are not removable without a cover lift are inspected in place.

As displayed in Figure 1, the hot gas path overhaul requires removal of the turbine section cover. It also requires removal of the gas turbine enclosure panels and, as part of this project, installation of an access hatch on the powerhouse building roof to allow lifting major components outside the powerhouse for inspection and overhaul.

3.2.1 Reliability Performance

Table 1 lists the 2015 to 2016 average capability factor, utilization forced outage probability (UFOP), and failure rate for the Holyrood Gas Turbine as compared to all of Hydro’s other gas turbine units (2012 to 2016) and the latest Canadian Electrical Association (CEA) averages (2011 to 2015). There have been no outages related to the hot gas path (HGP) components.

Table 1: Holyrood Gas Turbine Performance Data - All Causes.

Unit	Capability Factor (%)[1]	UFOP (%)[2]	Failure Rate[3]
Holyrood GT (2015/2016)[4]	93.51	2.19	20.17
Hardwoods GT (2012-2016)	71.69	15.95	76.71
Stephenville GT (2012-2016)	43.62	24.74	123.34
All Hydro GT Units (2012-2016)	70.72	20.51	61.94
CEA (2011-2015)	82.33	21.17	90.11

3.2.2 Vendor Recommendations

The internal mechanical components of a gas turbine unit wear differently when comparing a continuous duty application to a cyclic duty application. Thermal fatigue is the life limiter for peaking or cyclic loaded machines whereas creep, oxidation, and corrosion are the life limiters for continuous duty or base loaded gas turbines. For this reason, the gas turbine unit manufacturer has developed a maintenance schedule based on the number of total equivalent starts or total equivalent base hours of operation. The total equivalent starts[5] and total equivalent base hours monitor the thermal fatigue effect based on fuel type, operating hours, starts, trips, and load changes. The manufacturer recommends that the hot gas path inspection and overhaul be completed when either of the following criteria is met:

1. Total equivalent starts = 800; or
2. Total equivalent base hours = 24,000.

[1.] Capability Factor is defined as unit available time. It is the ratio of the unit's available time to the total number of unit hours.
[2] UFOP is defined as the Utilization Forced Outage Probability. It is the probability that a generation unit will not be available when required. It is used to measure performance of standby units with low operating time such as gas turbines.
[3] Failure Rate is defined as the rate at which the generating unit encounters a forced outage. It is calculated by dividing the number of transitions from an operating state to a forced outage by the total operating time.
[4] From March 1, 2015 to December 31, 2016.
[5] See Appendix A for sample calculation of equivalent starts.

The manufacturer has indicated that the majority of utilities operating this type of gas turbines have adopted the recommended maintenance strategy based on total equivalent starts and total equivalent base hours criteria.

3.2.3 Maintenance History

The two-year maintenance cost history for the Holyrood Gas Turbine is provided in Table 2.

Table 2: Two-Year Maintenance History

Year	Preventive Maintenance ($000)	Corrective Maintenance ($000)	Total Maintenance ($000)
2015	11.2	20.6	31.8
2016	81.8	320.8	402.6

4.0 Conclusion

Hydro has incorporated the on-going hot gas path inspections and overhauls into its long term plan to maintain reliable operations of the Holyrood gas turbine. According to Hydro's operational forecast, to avoid exceeding the total equivalent starts criteria, the first hot gas path inspection and overhaul of the gas turbine unit will need to be completed in 2019.

4.1 Budget Estimate

The project budget estimate is provided in Table 3.

Table 3: Project Budget Estimate

Project Cost: *($ x1,000)*	2018	2019	Beyond	Total
Material Supply	0.0	5.0	0.0	5.0
Labour	95.8	374.3	0.0	470.1
Consultant	81.1	0.0	0.0	81.1
Contract Work	5,997.6	1,756.4	0.0	7,754.1
Other Direct Costs	4.7	34.7	0.0	39.4
Interest and Escalation	359.6	767.4	0.0	1,127.0
Contingency	0.0	1,669.9	0.0	1,669.9
TOTAL	**6,538.8**	**4,607.7**	**0.0**	**11,146.5**

4.2 Project Schedule

The anticipated project schedule is provided in Table 4.

Table 4: Project Schedule

Activity		Start Date	End Date
Planning	Open Job; Prepare work breakdown structure (WBS); and Prepare scope statement.	January 2018	February 2018
Design	Prepare detailed design for roof access and associated roof modifications.	April 2018	May 2018
Procurement	Engage consultant for detailed design of roof access.	February 2018	March 2018
	Engage contractor for roof access installation and associated building modifications.	June 2018	July 2018
	Award contract for hot gas path inspection.	January 2019	April 2019
Construction	Complete roof access and associated building modifications.	August 2018	September 2018
	Perform hot gas path inspection and overhaul.	August 2019	September 2019
Closeout	Project Closeout.	November 2019	December 2019

Appendix A

Calculation of Equivalent Starts, Hours

Calculation of Equivalent Starts

The effects of thermal stress caused by starts, trips, and load changes are cumulative and are monitored using equivalent starts.

The equivalent starts calculation includes

ES = Σ(S * Sf*Ff) + Σ(A*Ff) + Σ(T*Tf*Ff) + Σ(I * Lf*Ff)

Where:

ES = Equivalent Start

S = Successful Start

A = Fired Abort

T = Trip from load

I = Instantaneous Load Change

Sf = Start Factor – normal start = 1; Fast start = 10

Tf = Trip Factor – based on load change % of base load

Lf = Load Change Factor – based on load change % of base load

Ff = Fuel Factor = 1.3 for distillate fuel

Definitions:

1. Fired Abort: A fired abort is a start attempt that aborts or is aborted after combustion ignition has occurred, but shuts down before reaching breaker closure.
2. Trip from load – A trip from load occurs if the unit is shutdown after breaker closure AND the normal shutdown full speed no load (FSNL) cool down sequence is not performed. This is a shutdown that does not follow the normal shut down sequence including but not limited to the specified FSNL cool down sequence.
3. Instantaneous Load Change – Instantaneous load change occurs when a unit abruptly increases or decreases load at a rate greater than the <u>specified ramp rate.</u>

Sample Calculation

Following is a sample equivalent starts calculation for a period of operation in which the listed events occurred.

10 successful starts – normal start

2 fired aborts

1 trip from load at 40MW

1 instantaneous load change from 80MW to full speed no load (FSNL)

$$ES = \Sigma(S * Sf*Ff) + \Sigma(A*Ff) + \Sigma(T*Tf*Ff) + \Sigma(I * Lf*Ff)$$

$$ES = (10*1.0*1.3) + (2*1.3) + (1*7.0*1.3) + (1*4.0*1.3)$$

$$= 13 + 2.6 + 9.1 + 5.2$$

$$= 29.9 \text{ ES}$$

So, in a month where there were 10 actual starts, the unit accumulated 29.9 equivalent starts due to fired aborts, trips and instantaneous load changes. A fuel factor of 1.3 is applied based on the use of diesel fuel.

Summary of Hydro's 2016 and 2017 Bi-Weekly and Monthly Reports

Report Date	Time Frame	CT usage (gWh)	YTD	Rationale	Description	Stoage Level (gWh)	Min. Storage (gWh)
March 2, 2016	Feb. 8-25, 2016	21.9	78.9	Support of Hydrology (lack of snow pack)	Units 1 and 2 at Holyrood were derated to 120 MW (from 170 MW) and Hardwoords was de-rated to 38 MW (from 50 MW)	1,251	1,106
March 14, 2016	Up to March 10, 2016	2.9	82.0	Support of Hydrology (lack of snow pack)	Units 1 and 2 at Holyrood were derated to 120 MW (from 170 MW) and Hardwoords was de-rated to 38 MW (from 50 MW)	1,544	1,008
March 28, 2016	Up to March 24, 2016	4.4	86.4	Support of Hydrology (lack of snow pack) & Low inflow	Units 1 and 2 at Holyrood were derated to 120 MW (from 170 MW) and Hardwoords was de-rated to 38 MW (from 50 MW)	1,398	895
April 11, 2016	Up to April 7, 2016	2.1	88.3	Support of Hydrology (lack of snow pack)	Units 1 and 2 at Holyrood were derated to 120 MW (from 170 MW) and Hardwoords was de-rated to 38 MW (from 50 MW)	1,468	825
April 25, 2016	Up to April 21, 2016	2.9	91.2	N/A	Units 1 and 2 at Holyrood were derated to 120 MW (from 170 MW), Hardwoords was de-rated to 38 MW (from 50 MW) and Stephenville gas turbine was de-rated to 25 MW (from 50 MW)	1,747	795
May 9, 2016	Up to May 5, 2016	1.9	93.1	Standby Generation	Units 1 and 2 at Holyrood were derated to 120 MW (from 170 MW), Hardwoords was de-rated to 38 MW (from 50 MW) and Stephenville gas turbine was de-rated to 25 MW (from 50 MW)	1,821	880
May 24, 2016	Up to May 9, 2016	-	93.1	N/A	Units 1 and 2 at Holyrood were derated to 120 MW (from 170 MW), Hardwoords was de-rated to 38 MW (from 50 MW) and Stephenville gas turbine was de-rated to 25 MW (from 50 MW)	2,111	1,170
June 6, 2016	Up to June 2, 2016	0.7	93.8	Standby Generation	Units 1 and 2 at Holyrood were derated to 120 MW (from 170 MW), Hardwoords was de-rated to 38 MW (from 50 MW) and Stephenville gas turbine was de-rated to 25 MW (from 50 MW)	2,146	1,425
June 20, 2016	Up to June 16, 2016	0.1	93.8	Standby Generation	Units 1 and 2 at Holyrood were derated to 120 MW (from 170 MW), Hardwoords was de-rated to 38 MW (from 50 MW) and Stephenville gas turbine was de-rated to 25 MW (from 50 MW). Stephenville GT off for Annual Maintenance, Unit 2 off for Annual Maintenance June 16	2,235	1,457
July 4, 2016	Up to June 30, 2016	-	93.8	N/A	Units 1 and 2 at Holyrood were derated to 120 MW (from 170 MW), Hardwoords was de-rated to 38 MW (from 50 MW) and Stephenville gas turbine was de-rated to 25 MW (from 50 MW). Stephenville GT off for Annual Maintenance, Unit 2 off for Annual Maintenance June 16	2,240	1,490
July 18, 2016	Up to July 14, 2016	-	93.8	N/A	Units 1 and 2 at Holyrood were derated to 120 MW (from 170 MW), Hardwoords was de-rated to 38 MW (from 50 MW) and Stephenville gas turbine was de-rated to 25 MW (from 50 MW). Stephenville GT off for Annual Maintenance, Unit 2 off for Annual Maintenance June 16	2,329	1,437
August 1, 2016	Up to July 28, 2016	-	95.3	N/A	Units 1 and 2 at Holyrood were derated to 120 MW (from 170 MW), Hardwoords was de-rated to 38 MW (from 50 MW) and Stephenville gas turbine was de-rated to 25 MW (from 50 MW). Stephenville GT off for Annual Maintenance, Unit 2 off for Annual Maintenance June 16. Unit 1 went off for Annual Maintenance	2,035	1,130
September 9, 2016	Up to August 30, 2016	-	95.3	N/A	Holyrood units back to 170 MW, Hardwoords was de-rated to 38 MW (from 50 MW) and Stephenville gas turbine was de-rated to 25 MW (from 50 MW)	2,035	1,130
October 13, 2016	Up to September 30, 20	3.5	98.8	Standby Generation	Hardwoords was de-rated to 38 MW (from 50 MW) and Stephenville gas turbine was de-rated to 25 MW (from 50 MW)	2,011	1,039
November 9, 2018	Up to September 30, 20	0.9	99.7	Standby Generation	Hardwoords was de-rated to 38 MW (from 50 MW) and Stephenville gas turbine was de-rated to 25 MW (from 50 MW)	2,326	1,092
December 9, 2016	Up to Novmber 30, 201	1.4	101.1	Standby Generation	Hardwoords was de-rated to 38 MW (from 50 MW) and Stephenville gas turbine was de-rated to 25 MW (from 50 MW)	2,397	1,172
January 10, 2017	Up to December 31, 20	13.4	114.5	Reliability	Unit 1 de-rated to 160 MW, Stephenville gas turbinen de-rated to 38 MW	2,125	1,142
February 10, 2017	Up to January 31, 2017	7.3	7.3	Reliability	Unit 1 de-rated to 145 MW, Unit 2 de-rated to 150 MW, Stephenville gas turbine de-rated to 38 MW	1,842	1,142

March 10, 2017	Up to February 28, 2017	10.8	18.1	Reliability	Unit 1 and 2 de-rated to 140 MW, Hardwoods de-rated to 25 MW, Stephenville gas turbine de-rated to 38 MW	1,465	1,142
April 10, 2017	Up to March 31, 2017	9.5	27.6	Reliability	All Holyrood units de-rated to 135 MW, Stephenville gas turbine de-rated to 25 MW	1,190	1,142
May 10, 2017	Up to April 30, 2017	2.9	30.5	Reliability	Unit 2 was offline for 2 weeks for annual maintenance, Unit 3 went off April 25 for Annual Maintenance. Stephenville gas turbine de-rated to 25 MW, Unit 1 de-rated to 125 MW	1,373	777
June 10, 2017	Up to May 31, 2017	2.7	33.2	Standby Generation	Unit 2 de-rated to 110 MW, Unit 2 was out all month, Unit 3 recalled, Stephenville gas turbine de-rated to 25 MW	2,110	1,420
July 10, 2017	Up to June 30, 2017	4.3	37.5	Standby Generation	Unit 2 de-rated to 165 MW, Unit 1 de-rated to 120 MW, Stephenville de-rated to 25 MW	2,194	1,490
August 10, 2017	Up to July 31, 2017	1.6	39.1	Standby Generation	Unit 2 de-rated to 165 MW, Unit 1 available but not required, Unit 3 back after first week from annual maintenance, Stephenville de-rated to 25 MW. Total Plant outage at Holyrood started July 31	1,989	1,373
September 11, 2017	Up to August 30, 2017	9.2	48.3	Reliability	Total Plant outage at Holyrood, Unit 3 online August 19, Hardwoods and Stephenville de-rated to 25 MW	1,802	1,130
October 10, 2017	Up to September 30, 20	-	48.3	N/A	Unit 2 offline for annual maintenance, Unit 1 back to full capacity Sept. 17, Unit 3 online, Stephenville de-rated to 25 MW	1,705	1,039
November 10, 2017	Up to October 31, 2017	3.9	52.2	Reliability	Unit 1 de-rated to 35 MW and then 135 MW, Unit 3 interm. De-rated through the month, unit 2 back online Oct 28	1,480	1,092
December 8, 2017	Up to November 30, 20	6.9	59.2	Reliability	Unit 1 de-rated to 135 MW, Unit 2 between 70-110 MW, Unit 3 de-rated to 130 MW, Stephenville de-rated to 38 MW	1,405	1,172
January 10, 2018	Up to December 31, 20	10.2	65.4	Reliability	Unit 1 de-rated to 150 MW, Unit 2 de-rated to 160 MW, Hardwoods de-rated to 25 MW	1,239	1,142