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March 29, 2018

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 – Application for Approval to Defer the 2015, 2016, and 2017 Balances in i) the Isolated Systems Supply Cost Variance Deferral Account; ii) the Energy Supply Cost Variance Deferral Account; iii) the Holyrood Conversion Rate Deferral Account

Enclosed please find the original plus 10 copies of Newfoundland and Labrador Hydro's (Hydro's) Application for approval to defer 2015, 2016, and 2017 balances in: i) the Isolated Systems Supply Cost Variance Deferral Account; ii) the Energy Supply Cost Variance Deferral Account; and iii) the Holyrood Conversion Rate Deferral Account. Hydro is not seeking recovery of these balances at this time; Hydro will raise the issue of recovery of any amounts approved in this Application as a part of its 2017 General Rate Application.

An application is required annually by March 31 for the disposition of the balance in each of the Isolated Systems Supply Cost Variance Deferral Account, the Energy Supply Cost Variance Deferral Account, and the Holyrood Conversion Rate Deferral Account. This Application is made in compliance with this requirement with respect to 2017 costs. Further, this Application seeks approval to defer 2015 and 2016 costs previously applied for and dismissed by the Board in Order No. P.U. 39(2017).

<u>Isolated Systems Cost Variance Deferral</u>
In Order No. P.U. 22(2017) the Board approved the Isolated Systems Cost Variance Deferral definition. The Isolated Systems Supply Cost Variance Deferral Account provides Hydro the opportunity to recover variances in the price of supply sources on Hydro's Isolated Systems. Hydro is seeking approval to defer balances consistent with the approved definition for 2015, 2016, and 2017.

<u>Energy Supply Cost Variance Deferral Account</u>
In Order No. P.U. 22(2017) the Board approved the Energy Supply Cost Variance Deferral Account definition. The Energy Supply Cost Variance Deferral Account captures variances in the cost of energy supplied to the Island Interconnected System, including variances in price

and volume of Hydro's own diesel and gas turbine generation, as well as variances in the volume of power purchases of wind generation, Corner Brook Pulp and Paper cogeneration, and hydraulic generation. Hydro is seeking approval to defer balances consistent with the approved definition for 2015, 2016, and 2017.

Holyrood Conversion Rate Deferral

In Order No. P.U. 22(2017) the Board approved the Holyrood Conversion Rate Deferral definition. The Holyrood Rate Deferral Account stabilizes fuel costs related to the Holyrood Fuel Conversation Rate. Hydro is seeking approval to defer balances consistent with the approved definition for 2015, 2016, and 2017.

The net amount requested for approval to defer from the above noted deferral accounts is approximately $65 million. Hydro is proposing that recovery of any amounts approved in this Application be dealt with through Hydro's 2017 General Rate Application.

Should you have any questions, please contact the undersigned.

Yours truly,

NEWFOUNDLAND AND LABRADOR HYDRO

Geoffrey P. Young
Corporate Secretary & General Counsel

GPY/bds
Encl.

cc: Gerard Hayes – Newfoundland Power
Paul Coxworthy – Stewart McKelvey Stirling Scales
Sheryl Nisenbaum – Praxair Canada Inc.
Dennis Browne, QC – Consumer Advocate
Dean Porter – Poole Althouse

ecc: Denis Fleming – Cox & Palmer
Larry Bartlett – Teck Resources Limited

Application

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

IN THE MATTER OF an Application by Newfoundland and Labrador Hydro for the Approval to Defer the balances in: i) the Isolated Systems Supply Cost Variance Deferral Account; ii) the Energy Supply Cost Variance Deferral Account; and iii) the Holyrood Conversion Rate Deferral Account, pursuant to Sections 70(1) and 80 of the *Act*.

TO: The Board of Commissioners of Public Utilities (the Board)

THE APPLICATION OF NEWFOUNDLAND AND LABRADOR HYDRO STATES THAT:

A. Background

1. Newfoundland and Labrador Hydro (Hydro) is a corporation continued and existing under the *Hydro Corporation Act*, is a public utility within the meaning of the *Act*, and is subject to the provisions of the *Electrical Power Control Act, 1994*.

2. In its 2013 Amended General Rate Application (GRA), Hydro proposed three new accounts for deferral and recovery of variances from its test year forecast of certain supply related costs. The proposed accounts included the Isolated Systems Supply Cost Variance Deferral Account, the Energy Supply Cost Variance Deferral Account, and the Holyrood Conversion Rate Deferral Account.

The Isolated Systems Supply Cost Variance Deferral Account

3. The Isolated Systems Supply Cost Variance Deferral Account provides Hydro with the opportunity to recover variances in the price of supply sources on Hydro's Isolated Systems. The account is credited or charged with the difference between the approved test year price and the actual cost of fuel and purchases used to serve Hydro's customers on its Isolated Systems.

4. In Order No. P.U. 49(2016) (the GRA Order), the Board stated that it believed that the Isolated Systems Supply Cost Variance Deferral Account should be approved effective January 1, 2015, but that recovery of the balance in the account should be addressed in the annual application for disposition of the balance in the account. The Board determined that Hydro should also file with its annual application a detailed report setting out the efforts made during the year to minimize the costs on the Isolated Systems and how any variance would be collected/refunded and from which customers. As such, the Board directed Hydro to file revised language for the Isolated Systems Supply Cost Variance Deferral Account to reflect the requirement for the detailed report with the annual disposition application.

5. On January 27, 2017, Hydro filed revised language to reflect the Board's direction. In Order No. P.U. 22(2017), the Board approved Hydro's revised Isolated Systems Supply Cost Variance Deferral Account definition.

The Energy Supply Cost Variance Deferral Account

6. The Energy Supply Cost Variance Deferral Account captures variances in the cost of energy supplied to the Island Interconnected System. The account applies to variances in the price and volume of Hydro's own diesel and gas turbine generation, as well as variances in the volume of power purchases from wind generation, Corner Brook Pulp and Paper cogeneration, and hydraulic generation. Further, this account also captures the energy supply costs or savings resulting from the variance in kWh supply based on the cost of generation at Holyrood Thermal Generating Station.

7. In the GRA Order, the Board stated that the proposed Energy Supply Cost Variance Deferral Account should be approved effective January 1, 2015, but required that the language of the account be revised with respect to power purchases variances to reflect variances in volume but not price. In addition, the Board found that the proposed account language was not sufficiently specific as to identify the supply sources which are to be reflected in the variances. As such, the Board directed Hydro to modify the account language to reflect these changes.

8. On January 27, 2017, Hydro filed revised language to reflect the Board's direction. In Order No. P.U. 22(2017), the Board approved the revised Energy Supply Cost Variance Deferral Account definition.

The Holyrood Conversion Rate Deferral Account

9. The Holyrood Conversion Rate Deferral Account stabilizes fuel costs related to the Holyrood fuel conversion rate. The account provides for the deferral of costs incurred by Hydro resulting from variations from the test year forecast associated with the Holyrood conversion rate.

10. In the GRA Order, the Board stated that the Holyrood Conversion Rate Deferral Account should be approved in relation to variances associated with the Holyrood conversion rate, effective January 1, 2015. However, the Board determined there should be a cost variance threshold of +/- $500,000 for the Holyrood Conversion Rate Deferral Account and directed Hydro to file revised account language for the Holyrood Conversion Deferral reflecting this change.

11. On January 27, 2017, Hydro filed revised language to reflect the Board's direction. In Order No. P.U. 22(2017), the Board approved the revised Holyrood Conversion Rate Deferral Account definition.

2017 Deferral and Recovery Application

12. On October 11, 2017 Hydro applied for deferral and recovery of the 2015 and 2016 supply costs through the Hydraulic Variation Account in the Rate Stabilization Plan. In Order No. P.U. 39(2017) the Board dismissed Hydro's Application and noted that Hydro's 2017 General Rate Application would be a convenient forum to address the issues related to the recovery of supply costs.

B. Application

Deferral Account Balances

13. Hydro is seeking approval as prudent, the following deferred supply costs:

i. 2015 Isolated Systems Supply Cost Variance Deferral Account balance of $0.00, as detailed in Appendix C to Schedule 1;

ii. 2016 Isolated Systems Supply Cost Variance Deferral Account credit balance of $2,186,570.00, as detailed in Appendix D to Schedule 1;

iii. 2017 Isolated Systems Supply Cost Variance Deferral Account credit balance of $1,106,821.00, as detailed in Appendix E to Schedule 1;

iv. 2015 Energy Supply Cost Variance Deferral Account debit balance of $14,200,429.00, as detailed in Appendix I to Schedule 1;

v. 2016 Energy Supply Cost Variance Deferral Account debit balance of $24,462,996.00, detailed in Appendix J to Schedule 1;

vi. 2017 Energy Supply Cost Variance Deferral Account debit balance of $20,134,732.00, detailed in Appendix K to Schedule 1;

vii. 2015 Holyrood Conversion Rate Deferral Account debit balance of $3,582,048.00, as detailed in Appendix M to Schedule 1;

viii. 2016 Holyrood Conversion Rate Deferral Account debit balance of $2,150,665.00, as detailed in Appendix N to Schedule 1; and

ix. 2017 Holyrood Conversion Rate Deferral Account debit balance of $4,163,799.00, as detailed in Appendix O to Schedule 1.

Balance Recovery

14. Due to the materiality of potential rate increases from other rate change applications currently before the Board, including but not limited to: i) Hydro's 2017 General Rate Application; ii) the discontinuance of the RSP mitigation adjustments on July 1, 2018; and iii) the normal operation of RSP adjustments in 2018, Hydro is proposing that the timing and method for recovery be dealt with through Hydro's 2017 General Rate Application.

C. Order Requested

15. Hydro hereby requests that the Board make and Order pursuant to Sections 70(1) and 80 of the *Act* approving:

    i. 2015 Isolated Systems Supply Cost Variance Deferral Account balance of $0.00;

    ii. 2016 Isolated Systems Supply Cost Variance Deferral Account credit balance of $2,186,570.00;

    iii. 2017 Isolated Systems Supply Cost Variance Deferral Account credit balance of $1,106,821.00;

    iv. 2015 Energy Supply Cost Variance Deferral Account debit balance of $14,200,429.00;

    v. 2016 Energy Supply Cost Variance Deferral Account debit balance of $24,462,996.00;

vi. 2017 Energy Supply Cost Variance Deferral Account debit balance of $20,134,732.00;

vii. 2015 Holyrood Conversion Rate Deferral Account debit balance of $3,582,048.00;

viii. 2016 Holyrood Conversion Rate Deferral Account debit balance of $2,150,665.00;

ix. 2017 Holyrood Conversion Rate Deferral Account debit balance of $4,163,799.00; and

x. that recovery of these balances be subject to a future order of the Board.

Reasons for Approval

16. The balances in the Isolated Systems Supply Cost Variance Deferral Account, the Energy Supply Cost Variance Deferral Account, and the Holyrood Conversion Rate Deferral Account were incurred in accordance with the definitions approved by the Board in Order No. P.U. 22(2017).

17. The costs in the Isolated Systems Supply Cost Variance Deferral Account, the Energy Supply Cost Variance Deferral Account, and the Holyrood Conversion Rate Deferral Account were prudently incurred in the provision of reliable service to customers.

18. Approval of the Hydro's Application provides a reasonable balance of the interests of the customers and the utility and will permit recovery of these supply costs to be considered in the context of other rate changes as a result of Hydro's 2017 General Rate Application.

DATED at St. John's, in the Province of Newfoundland and Labrador, this 29th day of March 2018.

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) 778-6671
Facsimile: (709) 737-1782

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

IN THE MATTER OF an Application by Newfoundland and Labrador Hydro for the Approval to Defer the balances in: i) the Isolated Systems Supply Cost Variance Deferral Account; ii) the Energy Supply Cost Variance Deferral Account; and iii) the Holyrood Conversion Rate Deferral Account, pursuant to Sections 70(1) and 80 of the *Act*.

AFFIDAVIT

I, Jennifer Williams, of St. John's in the Province of Newfoundland and Labrador, make oath and say as follows:

1. I am Vice President, 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 29th day of)
March 2018, before me:)

Barrister – Newfoundland and Labrador

Jennifer Williams

Schedule 1

Supply Cost Deferrals

2015, 2016, and 2017

Application Evidence

newfoundland labrador hydro
a nalcor energy company

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List of Appendices

1.0 Background

In Order No. P.U. 49(2016) (the GRA Order), the Board of Commissioners of Public Utilities (the Board) approved three new supply cost deferral accounts to become effective January 1, 2015: the Isolated Systems Supply Cost Variance Deferral Account (Isolated Systems Deferral); the Energy Supply Cost Variance Deferral Account (Energy Supply Deferral); and the Holyrood Conversion Rate Deferral Account (Holyrood Conversion Deferral). In the GRA Order, the Board also directed Newfoundland and Labrador Hydro (Hydro) to file revised account definitions for each account. In Order No. P.U. 22(2017), the Board approved Hydro's revised deferral account definitions. For reference, the approved deferral account definitions are included as Appendix A to this evidence.

On October 11, 2017, Hydro applied for recovery of approximately $42.2 million in supply costs incurred in 2015 and 2016. In Order No. P.U. 39(2017), the Board dismissed Hydro's application noting that the information provided did not adequately address the costs and benefits of Hydro's approach to generation dispatch and the alternatives which may be available, and whether the costs reflected in the accounts are reasonable and necessary to provide reliable service. Further, the Board was concerned with Hydro's proposed recovery method through the hydraulic variation component of the Rate Stabilization Plan.[1]

The evidence in this Application details the benefits provided to customers through Hydro's operational philosophy for generating unit dispatch and spinning reserve. Further, it includes detailed calculations and explanations of costs for each of the balances in the Isolated Systems Deferral, Energy Supply Deferral, and the Holyrood Conversion Deferral accounts for 2015, 2016, and 2017. The evidence in this Application addresses the Board's concerns from Order No. P.U. 39(2017) with respect to the costs and benefits of Hydro's approach to generation dispatch to demonstrate that the supply costs incurred for 2015, 2016, and 2017 were prudently incurred in the provision of reliable service to customers.

[1] Order No. P.U. 39(2017), page 3.

2.0 Hydro's Operational Philosophy

Since the power system outages in 2013, 2014, and 2015, Hydro has considered inputs from the Board and intervenors and adjusted its operations in response. Of particular relevance to this application are the changes Hydro made to its operation of standby generation when conventional generation[2] is not adequate to meet forecast system requirements (customer requirements, spinning, and non-spinning reserve). This change in operations combined with load growth and asset reliability resulted in material increased use of gas turbines to support the reliable operation of the system.[3] While the cost of the increased operation of gas turbines is material, Hydro believes that its operational philosophy and resulting operation and dispatch of gas turbines provides an appropriate balance of cost and reliability to customers.

The decision to proceed in operating generating units in this manner is a reflection of the lessons learned from the outages in 2013 through 2015, after which Hydro understood that outside parties' position was that Hydro had not been placing an appropriate focus on customer reliability and that a reexamination of the balance between cost and reliability was needed. In response, Hydro took a number of steps, one of which was that the Company adjusted its operation of generating units to ensure that reliability was a key element of its operational decision making. This adjustment in operations ensures that generation is already online and synchronized to the grid in the event of a system contingency, thereby mitigating the impact on customers. While this approach minimizes both the magnitude of the disruption as well as the number of customers impacted, this greater customer reliability focus carries with it greater costs associated with the increased use of gas turbines.

This adjusted approach to operations has been in place since 2015 and this philosophy, as well as the corresponding production data, has been communicated in both applications and submissions to the Board and intervenors since that time. An application for recovery of the

[2] Conventional generation refers to available generation excluding any gas turbine generation or interruptible arrangements in place, and wind generation beyond current day.
[3] Aligned with best practice reliability standards, Hydro operates its generation fleet (including thermal generation, emergency and standby generation) to position the power system to withstand the single worst contingency event.

costs of operation in this manner was first filed with the Board in October 2017. While Hydro recognizes that this was the first time that parties had been presented with the exact cost of this approach, there were several filings over the course of 2015 though 2017 that provided information regarding the magnitude of gas turbine generation resulting in the costs incurred.

Details regarding supply costs incurred as a result of increased gas turbine operations can be seen in Section 4 of this evidence with respect to the balance in the Energy Supply Deferral account.

2.1 Commentary on Hydro's Operational Culture and Reliability

Hydro's operations have been the subject of much review and scrutiny since the events of 2014 and 2015. In response to the events, the Board, its consultants, and intervenors have provided significant commentary and opinion on how Hydro should adjust its operations to increase its focus on customer reliability. Hydro accepted the commentary and opinion and has made efforts to adjust how it operates, demonstrating a shift toward an improved reliability focused operating culture.

Prior to the events of 2014 and 2015, Hydro did not have standard practices for starting emergency or standby units in advance of contingencies. In its final report regarding the outages of March 4, 2015,[4] Liberty Consulting (Liberty) stated:

> *<u>Hydro has continued to plan for and react to contingencies less aggressively than do many other utilities.</u> Liberty observed such an approach in our work associated with the January 2014 outages. Hydro's operating culture continues to comprise a matter of concern. With the operating culture issue identified in the aftermath of the January 2014 incidents, it nevertheless appears that Hydro has not accepted changing that culture as a priority. Liberty found that Hydro's reliability*

[4] Report dated October 22, 2015, relating to the Newfoundland and Labrador Hydro - March 4, 2015 Voltage Collapse.

> *culture contributed to the causation and to the management of the March 4 event.*
>
> *We have been critical of Hydro's approaches to and capabilities in reliability engineering. There have been numerous examples cited in our prior reports of reasoning that we have termed unusual at best. The events of March 4, 2015 provide another example. The characterization of the events as N-2 does not hold together. It may have made sense a day or two before the event, but not hours before the event, and certainly not now, months later. <u>Liberty continues to believe that Hydro should be significantly enhancing its capabilities to plan and manage reliability contingencies.</u> To suggest today that this event was N-2, and therefore unexpected and somehow acceptable, is wrong.*
>
> *<u>Our report following the January 2014 outages found a number of examples of non-standard industry thinking associated with reliability. The March 4th incident provides another telling example. This suggests that more conventional approaches and the skills to implement them are appropriate.</u>*
>
> [Emphasis added]

Through its investigation and summary report following the March 4, 2015 Avalon Voltage Collapse events, Liberty commented on Hydro's then lack of reliability culture and failure to plan for contingency events. Furthermore, Liberty indicated that Hydro has a *"non-standard industry thinking associated with reliability"*.

Recommendation 1 of Liberty's March 4 report was that "*Hydro should assign a team to implement a program to establish a more robust operational philosophy regarding reliability*." Hydro's submission on December 22, 2015 in response to Liberty's report included the following excerpt regarding recommendation 1:

> *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.*
> [Emphasis added]

In its submission relating to the Newfoundland and Labrador Hydro - March 4, 2015 Voltage Collapse events, Newfoundland Power stated that "[t]*he evidence is equally clear that Hydro could improve its reliability focus."* Further, the Consumer Advocate in its final submission on the Liberty report of March 4, 2015 Voltage Collapse events, stated *"The Consumer Advocate submits that it is important that Hydro fully implement the recommendations of Liberty, as these recommendations are well grounded and should, if fully implemented, improve on the reliability of service provided to customers."*

The Board, in its Phase One Report, provided commentary on Hydro's approach to reliability. Specifically, the Board expressed concern with respect to the reliability of supply on the Island Interconnected System,[5] Hydro's operating culture and reliability focused decision making,[6] and the requirement for deliberate change in its approach to customer reliability.[7]

Particularly relevant to the evolution of Hydro's operational philosophy the Board stated:

> *The Board acknowledges the challenges associated with balancing cost and reliability on the Island Interconnected system; however, the circumstances*

[5] Phase One Report, dated September 29, 2016, page 49, lines 32 through 36.
[6] Phase One Report, dated September 29, 2016, page 52, lines 5 through 7.
[7] Phase One Report, dated September 29, 2016, page 55, lines 36 through 42, Executive Summary, page i.

> *and risks must be carefully considered in making these difficult choices. In the Board's view Hydro did not demonstrate that it had completed the appropriate comprehensive analyses, balancing all of the risks and costs, in making these decisions.*[8]
> [Emphasis added]

It was clear to Hydro based on Liberty's report, the comments from Newfoundland Power, the Consumer Advocate and the decisions of the Board, that reliability required an increased focus.

2.2 Evolution of Hydro's Approach to Spinning Reserve

Following the March 4, 2015 events and in consideration of the party's commentary, as highlighted in Section 2.1, Hydro reviewed its reliability criteria. The Island Interconnected System reserve criterion was reviewed and formal spinning reserve targets were established to cover the loss of the single largest operating unit (N-1). This is typically in the range of 150-170 MW, depending on the largest unit in operation. By maintaining this level of spinning reserve, Hydro positions the System for an expedient restoration of customers in the event of the loss of a major generating unit.

Hydro also conducted focused analysis of the Avalon Peninsula, given the then-existing transmission constraints. Following the March 4, 2015 event, Hydro developed an Avalon operating instruction which provides for the method of assessment, stakeholder notification criteria, and operator dispatch guidelines related to Avalon capability and reserves.[9]

While Hydro had previously dispatched Holyrood units for Avalon reliability considerations, the implementation of regimented guidelines for operators, combined with the practice of starting Avalon standby units in advance of the contingency, significantly reduced Avalon exposure in

[8] Phase One Report, dated September 29, 2016, page 54, lines 29 through 33.
[9] Hydro conducted analysis to develop guidelines for the dispatch of Avalon generation, including standby sources, in order to withstand the next single worst contingency. Hydro's analysis included a series of load flow analysis, with various equipment in/out of service configurations, and with consideration to transmission line thermal ratings and delivery point voltages, identified the levels of Avalon loading or "thresholds".

terms of both likelihood and magnitude. Similar to the Island System, load growth and Holyrood unit availability through this period materially contributed to the requirement to run standby generation.

Board Order P.U. 49(2016) recognized the criticality of the Holyrood Gas Turbine (GT)[10] in enabling the provision of reliable service for customers. It states the following in response to Hydro's proposal for the establishment of the Energy Supply Cost Variance Account as part of its 2013 Amended GRA hearing:

> *The Board accepts that production from the Holyrood combustion turbine, like the Holyrood thermal generating station, is essential to the reliable and adequate supply of power on the Island Interconnected system.*[11]

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,[12] 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.

Hydro considers its dispatch of standby generation to provide system reliability prudent for the current system and consistent with the views of the Board's consultant, Liberty, with respect to reliability. Further Hydro has shared both Operating Instructions T-001 and T-096 with the Board and Intervenors, as well as an abundance of specific information around the usage of its

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[10] Also referred to as the Holyrood CT or Combustion Turbine.
[11] Order No. P.U. 49(2016) page 119, lines 4-6.
[12] Transcript pages 130-140 of http://pub.nl.ca/applications/NLH2013GRA-Amended/files/transcripts/Transcript-2015-10-20.pdf.

standby units in various reports. The provision of the Operating Instructions and information provided ample opportunity for dialogue between Hydro, the Board, and interested parties with respect to the changes in Hydro's operational philosophy, as well as the associated increased gas turbine production. To date, Hydro has received no indication from parties of disagreement with its operational philosophy.

2.3 Increased Reliance on Standby Generation

Consistent with past correspondence to the Board and Parties, Hydro now operates generation in advance to cover generation or transmission outages equal to the worst case contingency for either the Island Interconnected System or the Avalon Peninsula and to maintain spinning reserves.[13] This practice lowers both the risk of customer impact and the magnitude of the impact should a contingency occur.

From 2015 through 2017, the Island Interconnected System remained isolated from the remainder of the North American Grid. As such, Hydro was unable to draw upon neighbouring utilities using reserve sharing or emergency/security energy provisions under such contingencies. Therefore, generation was dispatched in advance of the contingency in order to mitigate the potential of sustained interruption to customers. Hydro operates all of its generation resources, under a least cost dispatch order, to position the system to withstand the single worst contingency event.

With load growth, Hydro's reliance on standby generation to provide for reliable service to customers has increased significantly in recent years. Standby units comprise a material portion of the overall Island generation fleet; therefore its use is required to maintain adequate reserves to position the Island Interconnected and Avalon systems to withstand the single worst contingency event. Based on identified requirements, and consistent with Operating Instructions T-001 and T-096, the Energy Control Center (ECC) will operate Hydro's fleet of

[13] Spinning reserve is defined as unloaded generation that is synchronized to the power system and ready to serve additional demand.

standby generation[14] in advance of the single largest contingency, rather than starting them after an event has occurred. Table 1 provides representative composition of the Island Interconnected System generation, assuming full unit availability.

Table 1 - Island Generation

Source	Gross Continuous Unit Rating (MW)
Hydroelectric[1]	1,130
Thermal[2]	490
Purchases[3]	89
Standby[4]	297
Total generation	**2,006**

Notes:
1. NLH and Customer owned
2. Holyrood
3. NLH purchases (includes Exploits)
4. NLH owned, NP owned and Vale

As such, customer requirements greater than the sum of available hydroelectric, thermal and purchases, which can vary based on planned and forced outages, would require the dispatch of standby generation.

2.4 Reliability Benefits for Customers

Hydro's revised operational practices since 2014 have been instrumental in its provision of improved reliability for customers.

Current operating practices ensure that should a contingency occur, there is generation online and synchronized to the grid to both minimize the magnitude of the disruption as well as the number of customers impacted. Appendix B provides several examples detailing Hydro's

[14] Hydro's standby generation includes the Hardwoods, Stephenville, and Holyrood gas turbines, the Holyrood diesel standby generating units, and the diesel units at St. Anthony and Hawkes Bay.

operational decisions, forecast Island spinning reserve, and forecast standby requirements for Avalon reserve for a number of weeks in 2015 through 2017.

The examples detailed in Appendix B illustrate the many inputs and complexities considered in the dispatch of standby generation. Largely, operation of standby generation in this time period was required to position the Island and Avalon systems to withstand the single worst contingency (i.e., maintain the system within static and dynamic limits, post contingency). In addition, during the winter of 2016 standby generation supplemented production from the Holyrood Thermal Generating Station to offset hydraulic generation and help conserve water storage in Hydro's reservoirs.

Hydro's dispatch of standby generation benefited customers through improved reliability from 2015 through 2017; the costs associated with standby generation production are detailed in Section 4.

2.5 Alternatives to Hydro's Approach

Hydro has seen an improvement in reliability associated with its evolved operating philosophy, specifically in the restoration of customers following unit trips which typically result in underfrequency load shedding (UFLS) on the system. Table 2 provides notable examples of the restoration times associated with similar loss of unit events before and after the change in Hydro's operating philosophy.

Table 2: Selected Underfrequency Load Shed Events

Prior to 2015							Online Reserve (MW)					
Date	**Event**	**Cause**	**Load Shed (MW)**	**Customers Impacted (Utility)**	**Customers Impacted (Industrial)**	**Island Reserve (MW)**	**Thermal**	**Hydro**	**Other (Customer Owned)**	**Total**	**Avalon Reserve (MW)**	**Restoration Time**
Feb 14, 2008 16:26	Holyrood Unit 3	Water in control cabinet of station service transformer UST3	127	19,012	2	128	19	106	N/A	125	N/A	Restoration began at 3 minutes, took 33 minutes to complete.
May 12, 2011 17:13	Holyrood Unit 1	Boiler trip due to low drum level	18.5	6,485	0	147	0	81	N/A	81	N/A	Restoration began at 7 minutes, all customers restored within 9 minutes
Oct 17, 2012 19:11	Holyrood Unit 1	Boiler trip due to high drum level	43	36,836	0	184	0	79	N/A	79	N/A	All customers restored within 11 minutes
Nov 25, 2012 11:24	Holyrood Unit 2	Equipment failure and operator error during an isolation procedure	16	6,660	0	188	0	73	N/A	73	N/A	All customers restored within 16 minutes
Jan 18, 2013 21:40	Bay d'Espoir Unit 4	Faulty current transformer on the unit	20.5	4,309	0	74	20	47	N/A	67	N/A	All customers restored within 15 minutes
Mar 10, 2013 16:33	Holyrood Unit 3	Faulty fuel oil pump	20	6,041	0	228	67	80	N/A	147	N/A	All customers restored within 11 minutes
Jul 29, 2014 09:43	Holyrood Unit 3	Human error during switching on station service supply for a planned maintenance outage	40	13,744	0	175	0	95	N/A	95	N/A	All customers restored within 11 minutes

Post 2015							Online Reserve (MW)					
Date	**Event**	**Cause**	**Load Shed (MW)**	**Customers Impacted (Utility)**	**Customers Impacted (Industrial)**	**Island Reserve (MW)**	**Thermal**	**Hydro**	**Other (Customer Owned)**	**Total**	**Avalon Reserve (MW)**	**Restoration Time**
Oct 01, 2015 22:08	Holyrood Unit 3	Operator error during weekly backwash on unit	22	4,655	1	244	0	192	N/A	192	N/A	Restoration began within 2 minutes, all Newfoundland Power customers restored within 4 minutes, all customers restored within 7 minutes
Nov 15, 2015 00:48	Holyrood Unit 1	Faulty positioning device on unit's governor system	12.4	5,437	0	466	178	151	48	377	N/A	All customers restored within 3 minutes
Nov 27, 2015 10:03	Holyrood Unit 1	Governor control system issue	96	18,498	1	227	52	106	14	172	N/A	Restoration began within 7 minutes, majority of customers restored within 10 minutes, all Newfoundland Power customers restored within 14 minutes
Mar 26, 2016 11:01	TL247 Tripped/ Cat Arm Units 1&2	TL 247 tripped due to ice bridging	100	26,307	0	238.3	6	219	0	225	184	Restoration began within 2 minutes, majority of customers restored within 15 minutes with exception of one Newfoundland Power feeder (restored within 24 minutes)
Aug 14, 2016 13:50	Holyrood Unit 3	Over temperature trip on unit transformer	11	6,951	0	353	50	216	20	286	425	Restoration began within 3 minutes, customers restored within 6 minutes

Post 2015							Online Reserve (MW)					
Date	**Event**	**Cause**	**Load Shed (MW)**	**Customers Impacted (Utility)**	**Customers Impacted (Industrial)**	**Island Reserve (MW)**	**Thermal**	**Hydro**	**Other (Customer Owned)**	**Total**	**Avalon Reserve (MW)**	**Restoration Time**
Aug 24, 2016 17:10	TL 234 Tripped/ Upper Salmon Unit/ Granite Canal Unit	Lightning strike to TL 234 isolated Upper Salmon and Granite Canal units from grid	27	6,804	1	304	32	240	14	286	263	Restoration began within 1 minute, majority of customers restored within 4 minutes with exception of one Newfoundland Power feeder.
Dec 08, 2016 13:10	Holyrood Unit 3	Faulty trip relay on unit service transformer	55	12,381	1	405	117	264	19	400	235	All customers restored within 6 minutes
Dec 20, 2016 18:05	Holyrood GT	Faulty thermocouple reading	57	9,439	1	248	44	172	13	229	205	All customers restored within 3 minutes
Dec 23, 2016 10:32	Holyrood Unit 1	Human error during procedure to change filters on the hydraulic system	56	11,669	1	320	98	172	0	270	275	All customers restored within 9 minutes

The data shows that for UFLS events prior to 2014, when Hydro had been operating with online reserves lower than the largest online unit, customer restoration times of eleven to sixteen minutes for UFLS events were not uncommon. Additionally, at that time system load was materially lower and generating equipment issues did not impact the ability to supply to the same extent. Further, prior to 2014, assets such as Holyrood TGS and Hardwoods GT were not as near end-of-life. Since implementing a spinning reserve target to cover the loss of Hydro's largest generating unit, customer restoration typically begins within 1-2 minutes and is typically complete within 6 minutes. This reduction in restoration time is in spite of load growth, concentration of load on the Avalon Peninsula, and higher unit unavailability through this period.

As an alternative to dispatching standby units in advance of contingencies, Hydro could hold standby generation as non-spinning reserve and dispatch units after an event has occurred and customers have experienced an interruption. Operating in this manner would increase the magnitude of load shed (i.e. an increased number of customers would lose service) and increase the time required to restore those same customers.[15] Had Hydro operated in that manner for 2015 through 2017, customer restoration times would have increased by an additional 30-40 minutes and a greater number of customers would have been impacted.[16] Given the increased level of customer impact, Hydro did not consider this a viable alternative given the feedback from the Board, Liberty, and its customers.

Hydro has continued to pursue additional opportunities to increase reliability for customers outside of standby generation. For the 2016-17 operating season, the Board approved Hydro's applications to enter into capacity assistance agreements with Praxair and Vale. Further, in advance of the winter 2017-18 operating season, the Board approved Hydro's request to enhance its existing capacity assistance arrangement with Corner Brook Pulp and Paper. The terms of the amended agreement both increase the capacity available to the system

[15] For UFLS events caused by unit trips.
[16] Assuming the start and loading of the Holyrood GT had been required to enable restoration.

operational flexibility in requesting capacity assistance. Hydro has made 16 requests for capacity assistance to date in the 2017-18 operating season.

3.0 Isolated Systems Cost Variance Deferral Account

Hydro purchases diesel fuel to supply customers on its isolated systems. Diesel fuel is a commodity and its price is set by market forces which can fluctuate greatly. This volatility and corresponding fuel price variance is beyond Hydro's control. As such, the Isolated Systems Deferral permits Hydro to defer variances from the approved test year in the price of supply costs in Hydro's isolated systems.

Hydro has three main supply sources for its isolated systems: 1) diesel fuel consumed in its diesel generation plants; 2) purchases from Hydro Quebec to serve customers on the L'Anse Au Loup system; and 3) purchases of wind energy in the community of Ramea on the south coast of the island of Newfoundland. Hydro's purchase price from Hydro Quebec and wind generation is adjusted based on the change in the price of diesel fuel.

The Isolated Systems Deferral account includes a Cost Variance Threshold (Deadband) of +/- $0.5 million per calendar year. This means that Hydro is only permitted to defer annual cost variances in excess of +/- $0.5 million that result from price changes relative to the Test Year cost of supply.

In the GRA Order, the Board determined that disposition of the balance in the account should be addressed in an annual application to the Board.[17]

3.1 Account Balances

Table 3 summarizes the amounts that have accumulated in the Isolated Systems Deferral for 2015 through 2017. Detailed calculations supporting Table 3 are included in Appendices C, D, and E to this evidence.

[17] Order No. P.U. 49(2016), page 116, lines 1-5.

Table 3 – Isolated Systems Deferral Summary ($000s)

Line No.	Particulars	Supply Cost Variances	Deadband	Net
1	2015 Isolated Systems Deferral	163	(500)	-
2	2016 Isolated Systems Deferral	(2,687)	500	(2,187)
3	2017 Isolated Systems Deferral	(1,607)	500	(1,107)
4	**Total**			**(3,294)**

In 2015, Hydro incurred approximately $0.2 million in supply costs in excess of its approved test year as a result of price variances in isolated system supply costs, primarily as a result of higher than forecast diesel fuel costs, which averaged the equivalent of 1.4 cents per kWh higher than the approved test year cost. However, as this amount is less than the approved Deadband of $0.5 million, this amount is not recoverable through the deferral account and the cost is borne by Hydro.

In 2016, Hydro realized isolated supply cost savings of approximately $2.7 million when compared to the approved test year. The 2016 savings were primarily a result of an average decrease in the cost of diesel fuel consumed at Hydro's generating facilities of approximately 2.7 cents per kWh and a corresponding decrease in the cost of power purchased from Hydro Quebec to serve customers on the L'Anse Au Loup system and wind generators in the community of Ramea. Accounting for the Deadband of $0.5 million, the credit balance in this deferral account is approximately $2.2 million.

In 2017, Hydro realized isolated supply cost savings of approximately $1.6 million when compared to the approved test year. These savings were primarily a result of an average decrease in the cost of diesel fuel consumed at Hydro's generating facilities of approximately 1.7 cents per kWh and a corresponding decrease in the cost of power purchased from Hydro Quebec to serve customers on the L'Anse Au Loup system and wind generators in the community of Ramea. Accounting for the Deadband of $0.5 million, the credit balance in this deferral account is approximately $1.1 million.

The total for the years 2015-2017 in this deferral account is a credit balance of approximately $3.3 million.

3.2 Cost Management in Isolated Systems

In the GRA Order, the Board directed Hydro to file a report with its annual application detailing Hydro's efforts during the year to minimize costs on the Isolated Systems. Appendices F, G, and H to this evidence contain Hydro's 2015, 2016, and 2017 Rural Deficit reports. These reports detail the initiatives undertaken by Hydro to minimize the costs of operating the Isolated Systems.

4.0 Energy Supply Cost Variance Deferral Account

From 2008 through 2015, Hydro acquired a number of new supply sources. These new supply sources, including Exploits, wind generation, and the Holyrood GT[18] benefit customers by providing increased system reliability and/or by reducing fuel consumption at the Holyrood TGS. In the absence of the Energy Supply Deferral account, variances in Hydro's energy supply costs could materially impact Hydro's financial results in a given year.

Hydro's purchases from Non-Utility Generators can also vary from test year levels. These variances, contributed by changes in wind and hydrology, are beyond Hydro's control and require Hydro to replace that energy with generation from more expensive sources, primarily the Holyrood TGS.

The Holyrood GT is essential to the reliable and adequate supply of power for customers on the Island Interconnected system; its operation is integral to ensuring adequate spinning reserves are present in the event of a system contingency. Variances from Hydro's approved test year in both volume and price associated with the Holyrood GT can be significant, and in the absence of a deferral mechanism, could result in a material reduction to Hydro's earnings.

[18] Also known as the Holyrood Combustion Turbine.

The Energy Supply Deferral permits Hydro to defer variances from the approved test year in the price of supply costs on Hydro's Island Interconnected System. The Energy Supply Deferral is comprised of three main sections: 1) variations in both price and volume of standby thermal generation; 2) variations in volume only from power purchases; and, 3) fuel cost variations at the Holyrood TGS as a result of variations in energy production from sources specifically covered by the Energy Supply Deferral. The Cost Variance Threshold (Deadband) for this account is +/- $0.5 million per calendar year; therefore, Hydro is only permitted to defer annual cost variances in excess of the Deadband.

4.1 Account Balances

Table 4 summarizes the deferral account activity in the Energy Supply Deferral for 2015 through 2017. Detailed calculations supporting Table 4 are included in Appendices I, J, and K to this evidence.

Table 4 – Energy Supply Deferral Summary ($000s)

Line No.	Particulars	Supply Cost Variances	Deadband	Net
1	2015 Energy Supply Deferral	14,700	(500)	14,200
2	2016 Energy Supply Deferral	24,963	(500)	24,463
3	2017 Energy Supply Deferral	20,635	(500)	20,135
4	**Total**			**58,798**

The account balance at the end of 2017 is a balance owing from customers of approximately $58.8 million. In accordance with the Deadband for this account, Hydro has absorbed $1.5 million in additional supply costs over the three year period from 2015 to 2017 that it will not recover from customers.

Appendix L to this Application provides a daily account of the generating units start and end times, durations and reason(s) for operation as well as a monthly summary of energy by unit, fuel consumption and cost for 2015 through 2017.

4.2 2015 Account Detail

The 2015 Energy Supply Deferral balance of $14.2 million is comprised of the costs summarized in Table 5.

Table 5 – 2015 Energy Supply Deferral Summary

Line No.	Particulars	$ 000s
1	Standby Generation Costs	11,182
2	Power Purchase Savings	(1,526)
3	Holyrood TGS Fuel Costs	5,044
4	Deadband	(500)
5	**Total**	**14,200**

The 2015 deferral balance primarily relates to increased standby thermal generation costs of approximately $11.2 million in excess of the amount forecast in the 2015 Test Year. The largest contributor to this variance was the Holyrood GT which produced 39.5 GWh in excess of test year levels.[19] The additional Holyrood TGS fuel costs were also material in 2015 as a result of reduced power purchases.

Details of the operating hours of the Holyrood GT for 2015 are shown in Table 6.

[19] The 2015 Test Year forecast included 6.5 GWh in production from the Holyrood GT.

Table 6 – Holyrood Gas Turbine 2015 Operating Data

Year	GT Function	Actual Starts	Actual Operating Hours	Reference Note
2015	Support of spinning reserve	28	205.5	1
	Backup due to the loss of a major generating unit	18	201.0	2
	Planned generation outages	21	181.2	3
	Planned Avalon Peninsula transmission outages	13	154.8	4
	Testing	15	45.8	5
	Total	**95**	**788.3**	

Notes: 1. Operation in this area includes for Spinning and Avalon Reserves which are generally load driven and/or due to deratings of generating equipment.
2. The primary driver of operation in this area was outages to units at the HTGS and requirements for Avalon and Spinning reserves.
3. The primary driver of operation in this area was the planned Holyrood total plant outage, necessary for maintenance of common systems, in August 2015 and therefore operation for Avalon transmission support.
4. The primary driver of operation in this area was the planned outage to the transmission line TL201 in November 2015.
5. Testing of the Holyrood GT primarily occurred in the months immediately following the commissioning and in-service date of the unit.

As Table 6 indicates, the uses of the Holyrood GT in 2015 were in support of spinning reserves, the provision of generation during the loss of a major generating unit, and to reliably facilitate planned generation and transmission outages. The increased generation from the Holyrood GT lessened the energy requirements from the Holyrood TGS, which produced savings that partially offset the increased GT costs.[20]

Hydro's power purchases were 78.2 GWh less than forecast in the 2015 Test Year from the non-utility generators specifically covered by the Energy Supply Deferral. As a result, Hydro incurred approximately $1.5 million less in power purchases costs in 2015, which was credited to the Energy Supply Deferral. The largest decrease in power purchases was from Nalcor Exploits, which produced 74.0 GWh less than the 2015 Test Year forecast. The decreased power

[20] Savings are reflected in Part C of the Energy Supply Deferral.

purchases from Nalcor Exploits were primarily due to operational issues and reduced inflows experienced at Exploits in 2015. These lower than forecast power purchases resulted in increased energy requirements from the Holyrood TGS.

Finally, Hydro incurred approximately $5.0 million in higher Holyrood TGS fuel costs in 2015 as a result of lower than forecast power purchases. For the generation sources specifically included in the Energy Supply Deferral, Hydro generated or purchased 993.9 GWh in total, versus the 2015 Test Year forecast of 1,042.3 GWh. This shortfall in energy of 48.4 GWh was replaced by generation from the Holyrood TGS. As such, the cost of this energy is charged to the Energy Supply Deferral at the approved test year fuel cost of energy at the Holyrood TGS.
In total, Hydro incurred an additional $14.7 million in additional energy supply costs on the Island Interconnected System in 2015. With the removal of the $0.5 million Deadband, Hydro is proposing to recover the $14.2 million reflected in the 2015 year-end balance.

4.3 2016 Account Detail

The 2016 Energy Supply Deferral balance of approximately $24.5 million is comprised of the costs summarized in Table 7.

Table 7 – 2016 Energy Supply Deferral Summary

Line No.	Particulars	$ 000s
1	Standby Generation Costs	25,060
2	Power Purchase Savings	(1,780)
3	Holyrood TGS Fuel Costs	1,683
4	Deadband	(500)
5	**Total**	**24,463**

In 2016, the Energy Supply Deferral balance primarily relates to increased thermal generation costs, which were approximately $25.1 million in excess of the amount forecast in the 2015 Test Year. The largest contributor to this variance was the Holyrood GT which produced 106.4 GWh in excess of 2015 Test Year forecast levels. Details of the 2016 operating hours of the Holyrood GT are shown in Table 8.

Table 8 – Holyrood Gas Turbine 2016 Operating Data

Year	GT Function	Actual Starts	Actual Operating Hours	Reference Note
2016	Support of spinning reserve	35	238.6	1
	Backup due to the loss of a major generating unit	5	1,245.6	2
	Planned Avalon Peninsula transmission outages	1	5.9	
	Testing	3	3.2	
	Total	**44**	**1,493.3**	

Notes: 1. Operation in this area includes Spinning and Avalon Reserves which are generally load driven and/or due to deratings to generating equipment.
2. The primary driver of operation in this area was the extended outages to HTGS Units 1 and 2 in January and February 2016 and the requirements for Avalon and Spinning reserves, as well as for reservoir support.

The Holyrood GT operating hours in 2016 were primarily due to extended outages to Units 1 and 2 at the Holyrood TGS in January and February 2016 due to boiler tube replacements. As a result of these unit outages, the production at the Holyrood GT was increased to maintain Avalon reserves which also had the effect of providing hydraulic reservoir support. Increased generation costs from the Holyrood GT in 2016 were partially offset by fuel savings resulting from lower energy production at the Holyrood TGS; these savings are reflected in Part C of the Energy Supply Deferral calculation.

Hydro's power purchases were 124.1 GWh less than forecast in the 2015 Test Year from the non-utility generators specifically covered by the Energy Supply Deferral. As a result, Hydro incurred approximately $1.8 million less in power purchase costs in 2016, which were credited to the Energy Supply Deferral. The largest decrease in power purchases was from Nalcor Exploits, which produced 138.1 GWh less than the 2015 Test Year forecast. The decreased power purchases available from Nalcor Exploits were primarily due to lower reservoir levels and planned equipment refurbishment at the Exploits generating units. Further, Hurricane Matthew flooded Bishop's Falls facility in October 2016, rendering some plant operations inoperable for approximately 2 months.[21] The lower power purchases resulted in increased energy requirements from the Holyrood TGS.

Hydro incurred approximately $1.7 million in higher Holyrood TGS fuel costs in 2016 as a result of lower power purchases than forecast in the 2015 Test Year. For the generation sources specifically included in the Energy Supply Deferral, Hydro generated or purchased 1,026.2 GWh in total, as compared to the 2015 Test Year forecast of 1,042.3 GWh. This shortfall in energy of 16.1 GWh, was replaced by more costly generation from the Holyrood TGS. As such, the cost of this energy is charged to the Energy Supply Deferral at the approved test year No. 6 fuel cost of energy at the Holyrood TGS.

In 2016, Hydro incurred approximately $25.0 million in additional supply costs. With the removal of the $0.5 million Deadband, Hydro is proposing to recover the approximately $24.5 million reflected in the year-end balance.

4.4 2017 Account Detail

The 2017 Energy Supply Deferral balance of approximately $20.1 million is comprised of the costs summarized in Table 9.

Table 9 – 2017 Energy Supply Deferral Summary

Line No.	Particulars	$ 000s
1	Standby Generation Costs	15,605
2	Power Purchase Savings	(1,080)
3	Holyrood TGS Fuel Costs	6,110
4	Deadband	(500)
5	**Total**	**20,135**

In 2017, the Energy Supply Deferral balance primarily relates to increased thermal generation costs, which were approximately $15.6 million in excess of the amount forecast in the 2015 Test Year. The largest contributor to this variance was the Holyrood GT which produced 58.3

[21] Various units in the plant came on line one by one over the course of the two months.

GWh in excess of 2015 Test Year forecast levels. Details of the 2017 operating hours of the Holyrood GT are shown in Table 10. The additional Holyrood TGS fuel costs were also material in 2017 as a result of reduced power purchases.

Table 10– Holyrood Gas Turbine 2017 Operating Data

Year	GT Function	Actual Starts	Actual Operating Hours	Reference Note
2017	Support of spinning reserve	63	629.9	1
	Backup due to the loss of a major generating unit	8	153.7	2
	Planned generation outages	26	349.2	3
	Planned Avalon Peninsula transmission outages	8	92.0	4
	Testing	2	3.5	
	Total	**107**	**1,228.3**	

Notes: 1. Operation in this area includes Spinning and Avalon Reserves which are generally load driven and/or due to deratings of generating equipment.
2. The primary drivers in this area were outages to Upper Salmon and Holyrood units 1 and 2.
3. The primary drivers in this area were planned outages to Holyrood units, including a total plant outage from July 30 to August 18.
4. The primary drivers in this area were planned outages to TL206, TL217 and TL201.

As Table 10 indicates, the uses of the Holyrood GT in 2017 were in support of spinning reserves, the provision of generation during the loss of a major generating unit, and to reliably facilitate planned generation and transmission outages. The increased generation from the Holyrood GT lessened the energy requirements from the Holyrood TGS, which produced savings that partially offset the increased GT costs; these savings are reflected in Part C of the Energy Supply Deferral calculation.

Hydro's power purchases were 107.1 GWh less than forecast in the 2015 Test Year from the non-utility generators specifically covered by the Energy Supply Deferral. As a result, Hydro incurred approximately $1.1 million less in power purchase costs in 2017, which were credited to the Energy Supply Deferral. The largest decrease in power purchases was from Nalcor

Exploits, which produced 114.3 GWh less than the 2015 Test Year forecast. The decreased power purchases available from Nalcor Exploits were primarily due to lower reservoir levels and reduced river flows in 2017, as well as a required stator rewind of Grand Falls Unit 4. The lower power purchases resulted in increased energy requirements from the Holyrood TGS.
Hydro incurred approximately $6.1 million in higher Holyrood TGS fuel costs in 2017 as a result of lower power purchases than forecast in the 2015 Test Year. Hydro generated or purchased 983.7 GWh in total from allowable generation sources included in the Energy Supply Deferral, versus the 2015 Test Year forecast of 1,042.3 GWh. This shortfall in energy of 58.6 GWh, was replaced by more costly generation from the Holyrood TGS. As such, the cost of this energy is charged to the Energy Supply Deferral at the approved test year No. 6 fuel cost of energy at the Holyrood TGS.

In 2017, Hydro incurred approximately $20.6 million in additional supply costs. With the removal of the $0.5 million Deadband, Hydro is proposing to recover the approximately $20.1 million reflected in the year-end balance.

The total balance in the Energy Supply Deferral for the years 2015 through 2017 is a balance owing from customers of approximately $58.8 million. Approximately $12.8 million of this balance is attributable to increased production at the Holyrood TGS as a result of variations in production from defined supply sources.[22]

5.0 Holyrood Conversion Deferral

The Holyrood Conversion Deferral permits Hydro to defer costs that result from differences between the actual and Test Year No. 6 fuel conversion rate. The Holyrood TGS conversion rate can be affected by unit loading and fuel BTU content. Generally higher unit loading at the Holyrood TGS will improve the conversion rate and result in fuel savings, and, conversely, lower unit loading at the Holyrood TGS will reduce the conversion rate and result in higher fuel costs. Further, when fuel BTU content is lower than Hydro's specification, this results in a lower

[22] Expressed as 'Part C – Holyrood TGS Fuel Costs/(Savings)' in the calculation of the Energy Supply Deferral.

conversion rate and therefore more fuel must be consumed to achieve the same level of energy production.

For the purpose of calculating Hydro's test year fuel costs and monthly Rate Stabilization Plan (RSP) balances, a fixed conversion rate is used for the number of kWh output for each barrel of No. 6 fuel consumed by the Holyrood TGS. Hydro's approved No. 6 conversion rate for the 2015 Test Year is 618 kWh per barrel.[23] Hydro is permitted to defer annual costs in excess of the Cost Variance Threshold (Deadband) of +/- $0.5 million per calendar year.

5.1 Account Balances

Table 11 summarizes the deferral account activity in the Holyrood Conversion Deferral for 2015, 2016, and 2017. Detailed calculations supporting Table 11 are included in Appendices M, N, and O to this evidence.

Table 11 – Holyrood Conversion Deferral ($000s)

Line No.	Particulars	Supply Cost Variances	Deadband	Net
1	2015 Holyrood Conversion Deferral	4,082	(500)	3,582
2	2016 Holyrood Conversion Deferral	2,651	(500)	2,151
3	2017 Holyrood Conversion Deferral	4,664	(500)	4,164
4	**Total**			**9,897**

The account balance at the end of 2017 is an amount owing from customers of approximately $9.9 million. In accordance with the Deadband in the approved deferral account definition, Hydro has absorbed $1.5 million in additional supply costs from 2015 through 2017 that it will not recover from customers.

5.2 2015 Account Balance

The 2015 actual conversion rate of 602 kWh per barrel at the Holyrood TGS resulted in Hydro incurring approximately $4.1 million in additional No. 6 fuel costs. In 2015, Hydro achieved a

[23] Board Order No. P.U. 49(2016), page 32, lines 25-26.

fuel conversion rate of 602 kWh per barrel compared to the 2015 Test Year rate of 618 kWh per barrel. The variance from the test year conversion rate was primarily due to a lower average unit loading than forecast in the test year, which contributed to a lower fuel conversion rate.[24] A contributor to the lower average unit loading was the requirement to operate a Holyrood unit at minimum loads during the summer months in order to support Avalon reserves, which supports system reliability for customers.

Further, No. 6 fuel deliveries in 2015 contained a lower average BTU content than what was forecast in the 2015 Test Year,[25] which contributed to the lower actual conversion rate in 2015. When Hydro receives fuel with an actual BTU lower than specified, Hydro receives a discount on its purchase of No. 6 fuel, and this savings is passed on to customers through the RSP.[26] Finally, the station service factor for 2015 was higher than what was approved in the 2015 Test Year, resulting in greater station service losses in 2015.[27]

5.3 2016 Account Balance

The 2016 actual conversion rate of 608 kWh per barrel resulted in Hydro incurring approximately $2.7 million in additional No. 6 fuel costs. In 2016, Hydro achieved a fuel conversion rate of 608 kWh per barrel compared to the 2015 Test Year rate of 618 kWh per barrel. The variance from the test year conversion rate for 2016 was primarily due to a lower average unit loading than forecast in the test year.[28] A contributor to the lower average unit loading was operating of a Holyrood unit at minimum loads during the summer months in order to support Avalon reserves, which supports system reliability for customers.

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[24] Hydro's 2015 Test Year forecasted an average unit loading of 109.6 MW; the actual 2015 average unit loading was 88.9 MW.

[25] 2015 Test Year average fuel heating content was 152,400 BTU/gal. Actual 2015 fuel heating content averaged 150,581 BTU/gal.

[26] For each delivery of No. 6 fuel if the BTU content does not meet the contracted specification, the purchase price is reduced to reflect the actual BTU content of delivered fuel.

[27] 2015 Actual station service factor was 5.81% vs. the 2015 Test Year approved factor of 5.00% (618 kWh/bbl).

[28] Hydro's 2015 Test Year forecasted an average unit loading of 109.6 MW; the actual 2016 average unit loading was 90.8 MW.

Further, No. 6 fuel deliveries in 2016 contained a slightly lower average BTU content than what was forecast in the 2015 Test Year,[29] which contributed to the lower actual conversion rate in 2016. When Hydro receives fuel with an actual BTU lower than specified, Hydro receives a discount on its purchase of No. 6 fuel, and this savings is passed on to customers through the RSP.[30] Finally, the station service factor for 2016 was higher than what was approved in the 2015 Test Year, resulting in greater station service losses.[31]

5.4 2017 Account Balance

The 2017 actual conversion rate of 602 kWh per barrel resulted in Hydro incurring approximately $4.7 million in additional No. 6 fuel costs. In 2017, Hydro achieved a fuel conversion rate of 602 kWh per barrel compared to the 2015 Test Year rate of 618 kWh per barrel. The variance from the test year conversion rate for 2017 was primarily due to a lower average unit loading than forecast in the test year.[32] A contributor to the lower average unit loading was the requirement to operate a Holyrood unit at minimum loads during the summer months in order to support Avalon reserves, which supports system reliability for customers.

In addition, the station service factor in 2017 was higher than what was approved in the 2015 Test Year, resulting in greater station service losses in 2017.[33] The average BTU content of No. 6 fuel deliveries in 2017 slightly exceeded what was forecast in the 2015 Test Year, and therefore did not contribute to the balance in this account.[34]

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[29] 2015 Test Year average fuel heating content was 152,400 BTU/gal. Actual 2016 fuel heating content averaged 152,315 BTU/gal.

[30] For each delivery of No. 6 fuel, the purchase price is adjusted to reflect the BTU content of the delivered fuel.

[31] 2016 Actual station service factor was 5.32% vs. the 2015 Test Year approved factor of 5.00%.

[32] Hydro’s 2015 Test Year forecasted an average unit loading of 109.6 MW; the actual 2017 average unit loading was 94.0 MW.

[33] 2017 Actual station service factor was 5.57% vs. the 2015 Test Year approved factor of 5.00%.

[34] 2015 Test Year average fuel heating content was 152,400 BTU/gal. Actual 2017 consumption averaged 152,490 BTU/gal. If delivered fuel contains a lower BTU content than specified per the contract, the purchase price is adjusted to reflect the actual BTU content of the delivered fuel. If delivered fuel contains a higher BTU content than contracted, no adjustment is made to the purchase price.

The total for the years 2015-2017 in this deferral account is a balance owing from customers of approximately $9.9 million.

6.0 Proposed Recovery of Supply Costs

Hydro is proposing to defer consideration of recovery of the 2015, 2016, and 2017 Supply Deferral costs to be dealt with through Hydro's 2017 GRA.

7.0 Conclusion

Hydro is seeking approval to defer approximately $65.4 million in prudently incurred supply costs from 2015 through 2017, as summarized in Table 12.

Table 12– Summary of Deferral Account Balances

Line No.	Particulars ($ 000s)	2015	2016	2017	Total
1	Isolated Systems Deferral	-	(2,187)	(1,107)	(3,294)
2	Energy Supply Deferral	14,200	24,463	20,135	58,798
3	Holyrood Conversion Deferral	3,582	2,151	4,164	9,897
4	**Total**	**17,782**	**24,427**	**23,192**	**65,401**

The Isolated Systems Deferral is proposed to refund approximately $3.3 million to customers as a result of lower than forecasted diesel fuel prices and power purchases in isolated communities. The Energy Supply Deferral has accumulated approximately $58.8 million in costs primarily as a result of increased production from the Holyrood GT which provided Hydro's customers with greater reliability, as well as increased production at the Holyrood TGS due to lower available hydraulic power purchases. Finally, the Holyrood Conversion Deferral has accumulated approximately $9.9 million in costs as a result of a lower than forecast conversion rate at the Holyrood TGS, primarily as a result of lower unit loading than what was forecast in Hydro's approved test year.

As noted in Section 2 of this evidence, Hydro's approach to dispatch of its standby generating units is strikes an appropriate balance between cost and reliability, is consistent with the recommendations of the Board's consultant Liberty, and has resulted in increased reliability for customers.

Section 80 of the *Public Utilities Act* states that a public utility is entitled to earn annually a just and reasonable return as determined by the Board, and that the return shall be in addition to those expenses that the Board may allow as reasonable and prudent. The Supply Costs outlined in Table 12 were prudently incurred in the provision of reliable service to customers and as such, Hydro requests approval to defer these costs as prudently incurred in accordance with section 80 of the *Act* with recovery to be determined at the conclusion of Hydro's 2017 GRA.

Appendix A
Approved Account Definitions

NEWFOUNDLAND AND LABRADOR HYDRO
ISOLATED SYSTEMS SUPPLY COST VARIANCE DEFERRAL ACCOUNT

This account shall be charged or credited with the amount by which Hydro's Isolated Systems Supply Cost Variance exceeds the Supply Cost Variance Threshold in a calendar year.

The ***Isolated Systems Supply Cost Variance*** will be determined by the following formula:

$$A \times (B-C)$$

Where:

A = Total actual supply produced and purchased (kWh) on Hydro's isolated systems.

B = (Total actual cost of No. 2 fuel used to provide energy plus the total actual cost of purchases) divided by the total of the (actual kWh production and the actual kWh purchases) in $/kWh.

C = (Total Test Year cost of No. 2 fuel used to provide energy plus the total Test Year cost of purchases) divided by the (total of the Test Year kWh production and the Test Year kWh purchases) in $/kWh.

The ***Supply Cost Variance Threshold*** equals ±$500,000 in a calendar year.

Disposition of any Balance in this Account
Hydro shall file an Application for the disposition of any balance in this account with the Board no later than the 31st day of March each year. This Application shall detail the proposed method of collection or refund and from which customer class(s), and the efforts made by Hydro during the year to minimize costs on the Isolated systems.

NEWFOUNDLAND AND LABRADOR HYDRO
ENERGY SUPPLY COST VARIANCE DEFERRAL ACCOUNT

This account shall be charged or credited with the Energy Supply cost variance incurred by Hydro on the Island Interconnected System that is in excess of the Cost Variance Threshold in the calendar year.

Variations resulting from both the price and volume of the following thermal generation sources shall be charged or credited to this account:

- Holyrood Combustion Turbine;
- Hardwoods Gas Turbine;
- Stephenville Gas Turbine;
- St. Anthony Diesel Plant; and
- Hawkes Bay Diesel Plant.

Variations resulting from the volume of the following power purchases shall be charged or credited to this account:

- Nalcor Exploits;
- Star Lake;
- Rattle Brook;
- CBPP Cogeneration;
- St. Lawrence wind; and
- Fermeuse wind.

Energy Supply costs will be determined by the following formula:

A + B + C

A = Test Year Thermal Generation Variances resulting from both price and volume;

Where:

A = (Actual Thermal Generation Cost – Test Year Thermal Generation Cost)

B = Test Year Power Purchase Variances resulting from volume;

Where:

B = (Actual kWh Purchases – Test Year kWh Purchases) x (Test Year Purchase Cost in $/kWh)

NEWFOUNDLAND AND LABRADOR HYDRO
ENERGY SUPPLY COST VARIANCE DEFERRAL ACCOUNT (continued)

C = Fuel costs or savings resulting from the variance in generation at the Holyrood Thermal Generating Facility (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 = [(Test Year kWh Thermal Generation + Test Year kWh Power Purchases) - (Actual kWh Thermal Generation + Actual kWh Power Purchases)] for all defined sources.

The ***Cost Variance Threshold*** equals ±$500,000 in a calendar year.

Disposition of any Balance in this Account
Hydro shall file an Application for the disposition of any balance in this account with the Board no later than the 31st day of March each year.

NEWFOUNDLAND AND LABRADOR HYDRO
HOLYROOD CONVERSION RATE DEFERRAL ACCOUNT

This account shall be charged or credited with the Conversion Rate Cost Variance incurred by Hydro on the Island Interconnected system, in excess of the Cost Variance Threshold in the calendar year, which results from variations from the Test Year fuel conversion rate at the Holyrood thermal generating station.

The ***Conversion Rate Cost Variance*** will be determined monthly by the following formula:

$$(A - B) \times C$$

A = Actual quantity of No. 6 fuel consumed (bbl);

B = Calculated quantity of No. 6 fuel consumed using the Cost of Service fuel conversion rate (bbl); and

C = Test Year Cost of Service No. 6 fuel cost ($/bbl).

Where:

$$B = D/E$$

D = Actual net Holyrood production (kWh); and

E = Test Year Cost of Service fuel conversion rate (kWh/bbl).

The ***Cost Variance Threshold*** equals ±$500,000 in a calendar year.

Disposition of any Balance in this Account
Hydro shall file an Application for the disposition of any balance in this account with the Board no later than the 31st day of March each year.

Appendix B
Specific Examples of the Requirement for Standby Generation

APPENDIX B

SPECIFIC EXAMPLES OF THE REQUIREMENT FOR STANDBY GENERATION

Table of Figures

This section provides examples of Hydro's operations during 2015 through 2017. The weeks included in this analysis were selected to provide insight into the myriad of operational requirements that can result in standby generation.

For each week provided:

- the text provides insight into Hydro's operations during that week;
- the first figure provides Hydro's forecast Island spinning reserve (where available); and
- the second figure provides forecast standby requirements for Avalon reserves (where available).

Interpreting the Figures:

The figures included in this analysis indicate what Hydro's forecast requirements would have been at that time.

Island Spinning Reserve Chart

In the first figure, in any instance the blue line represents conventional generation available to contribute to Island spinning reserve. As load grows through the day, the available conventional generation that can contribute to Island spinning reserve decreases as that generation is being used to meet customer requirements at that time. The red line represents the capacity of the largest online unit at that time (the n-1 contingency). In instances where the available conventional generation (value indicated by the blue line) is less than that of the n-1 contingency (value indicated by the red line) standby generation would be dispatched on a forecast basis to provide sufficient Island spinning reserve.

Standby Forecast for Avalon Reserves Chart

The second figure illustrates the gross Avalon loading (MW) by day. Blue chart area indicates the level of gross Avalon loading that could be supported with no standby units dispatched. Green chart area indicates that staffing of Avalon standby generation is required to ensure Hydro can appropriately respond to changing system conditions. Red chart area indicates that standby generation is required to be online and synchronized to the grid to position the system for the single worst Avalon contingency. Standby generation is then dispatched in accordance with the threshold lines included on the figure. The threshold lines provide indication of the gross Avalon loading that could be supported with the available Avalon standby generation, in a least-cost dispatch. Threshold limits vary based on the number of Holyrood units online and the status of Avalon transmission equipment at that time.

Note that the forecast Island spinning reserve and forecast standby requirements for Avalon reserves were developed within this time period and have been provided where available. The data contained in these files are inputs when deciding to place standby units online.

Additionally, production on specific days had been questioned by Newfoundland Power in RFIs as part of Hydro's previous filing.[1] Hydro's operations, at that time, were addressed in the responses to those RFIs and as such have not been included in this analysis.

To plan operations for required spinning reserve, the Nostradamus forecast customer load is compared to available generation that can contribute to spinning reserve. Hydro will operate the system, dispatching units in accordance with Hydro's operating instruction regarding generation reserves, to meet system requirements in accordance with economic dispatch.

As actual customer load is dynamic for several reasons,[2] Hydro's experience is that it is normal for actual customer load to vary up or down by tens of MW from forecast. This is especially important to be mindful of when operating the system heading into morning and evening peak. Hydro considers this and will plan to operate its generation, including standby units, if forecast load is expected to approach the spinning reserve limit.

[1] Application for Recovery of 2015 and 2016 Supply Costs, dated October 11, 2017, Hydro's response to NP-NLH-30 and NP-NLH-31.

[2] As with any forecasting analysis, there will be discrepancies between the forecasted and actual values. Typical sources of variance in the load forecasting are differences in the industrial load forecast due to unexpected changes in industrial customer loads, inaccuracies in the weather forecast, particularly temperature, wind speed, or cloud cover; and non-uniform customer behaviour which results in unpredictability. Through 2015-2017 Hydro reported on the accuracy of its forecasting software semi-annually to the Board.

By placing units online in advance of a contingency, operational and potential reliability risks are reduced in two ways; first, actual load can change materially from forecast with peaks higher than forecast, second, equipment issues could impact the ability to get additional reserves online in a timely fashion. These factors could result in system risk that potentially cannot be addressed in time to avoid interruptions or power quality issues. As such, in consideration of the examples provided in this section, there are times when gas turbines have been dispatched on a forecast basis when on an actual basis the spinning reserve limit was not violated. There are also instances when the evidence would suggest additional generation should have been placed online based on actual spinning reserve, and this can also be as a result of changes in actual load compared to forecast.

In each instance, the decision to operate standby could have been the result of forecast Island spinning reserves, forecast standby requirements for Avalon reserves, an outage to a transmission line, or in response to an operational situation.

Specific Examples of Standby Generation Required in 2015[3]

Week of October 29, 2015 to November 4, 2015

During this week, standby generation was required to support both load and Island spinning reserves on November 3, 2015 and November 4, 2015. Island spinning reserve would have been below the level required to sustain the loss of the largest online unit for both the morning and evening peak on both days. In this week, Holyrood Unit 1 was unavailable due to ongoing annual maintenance[4], the Stephenville GT was unavailable, and various hydraulic units were unavailable (Unit 4 at Bay d'Espoir, Hinds Lake, and Cat Arm Unit 1). On November 4, 2015, the Hardwoods GT was derated to 38 MW in advance of the evening peak.[5]

[3] Note that as Hydro's toolsets were in development through 2015, no forecast charts are available for the first example noted.

[4] Hydro generally completes maintenance outside the Winter Readiness period, December 1 to March 31, so it is normal to have generating units or transmission lines unavailable in November.

[5] Newfoundland and Labrador Hydro, Supply and Demand Status Reports, dated November 3, and 4 2015.

Week of December 24, 2015 to December 30, 2015

During this week, standby generation was required to support both load and Island spinning reserves from December 28-30, 2015. The Holyrood GT unit was started on December 28, 2015 at 15:00 in advance of the evening peak. It was required for both morning and evening peak on December 29, 2015. It was dispatched similarly on December 30, 2015. Forecast demand exceeded 1600 MW during that time period. Additionally, during this time the actual peaks experienced were higher than forecast, likely reflecting cold temperatures and incremental Christmas demand, further supporting reliability-focused decision making.

As evident in Figure 1, on a forecast basis, conventional generation was unable to maintain required spinning reserve. As demonstrated in Figure 2, on a forecast basis, standby generation was required to support Avalon reserves. In this week all units were available, with Holyrood Unit 1 de-rated to 155 MW.[6]

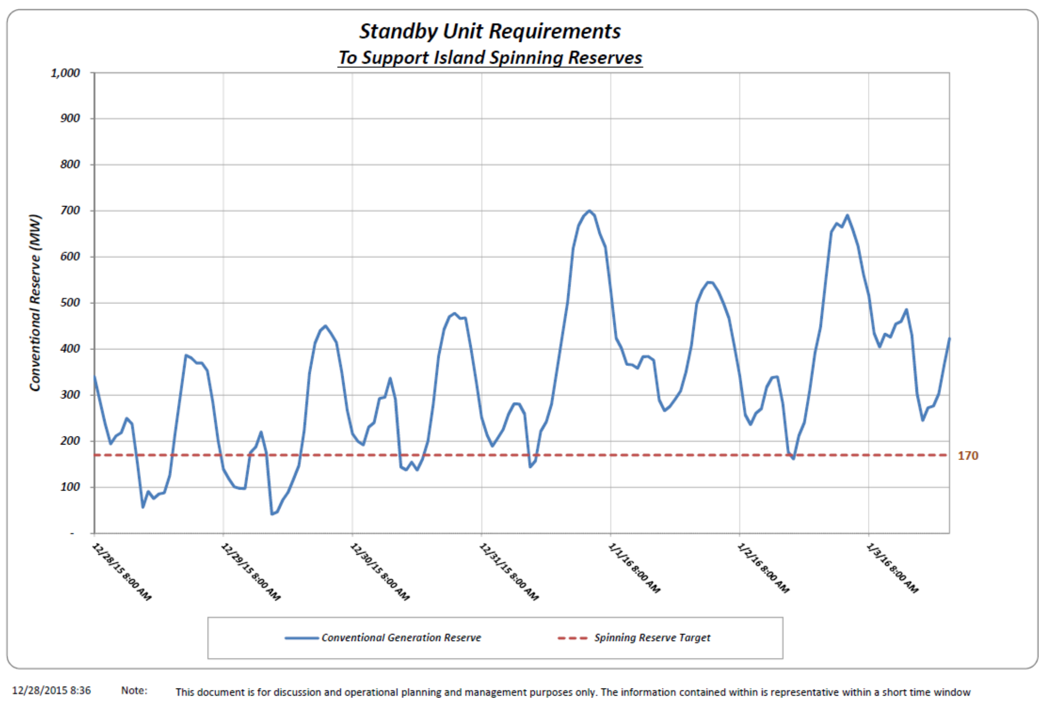


Figure 1: Island spinning reserve forecast December 28, 2015 - January 3, 2016

[6] Newfoundland and Labrador Hydro, Supply and Demand Status Reports, dated December 28, 29, and 30 2015.

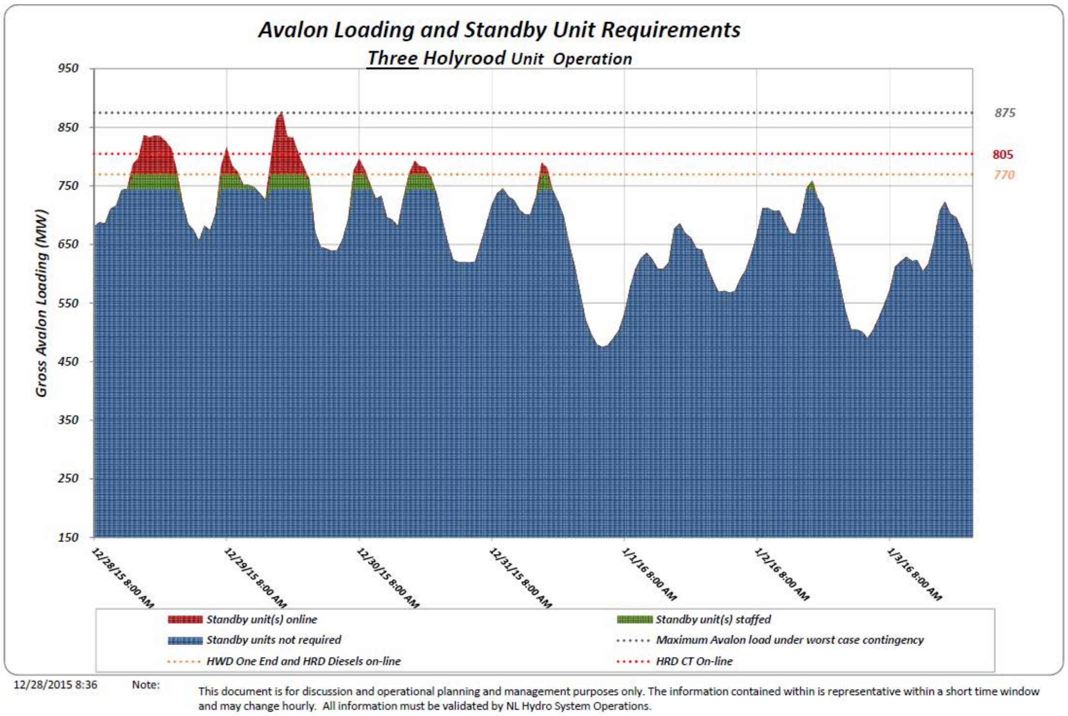


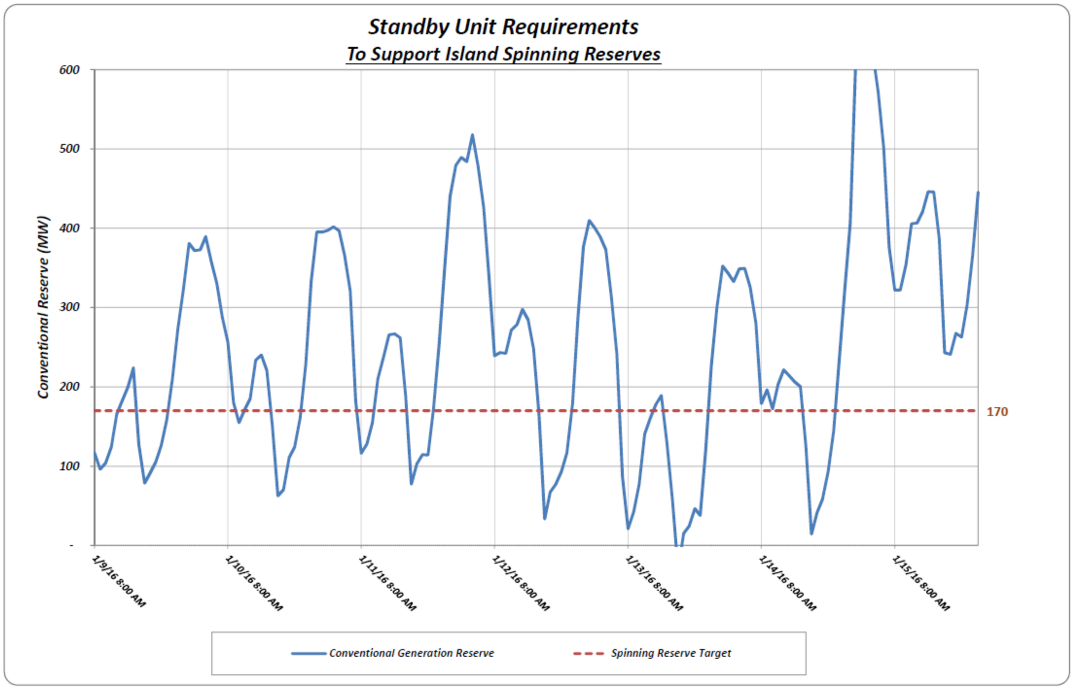
Figure 2: Standby forecast for Avalon reserves December 28, 2015 - January 3, 2016

Specific Examples of Standby Generation Required in 2016

Weeks of January 8-14, 2018, January 22-28, 2015, February 12-18, 2018, and February 26, 2016 to March 3, 2016

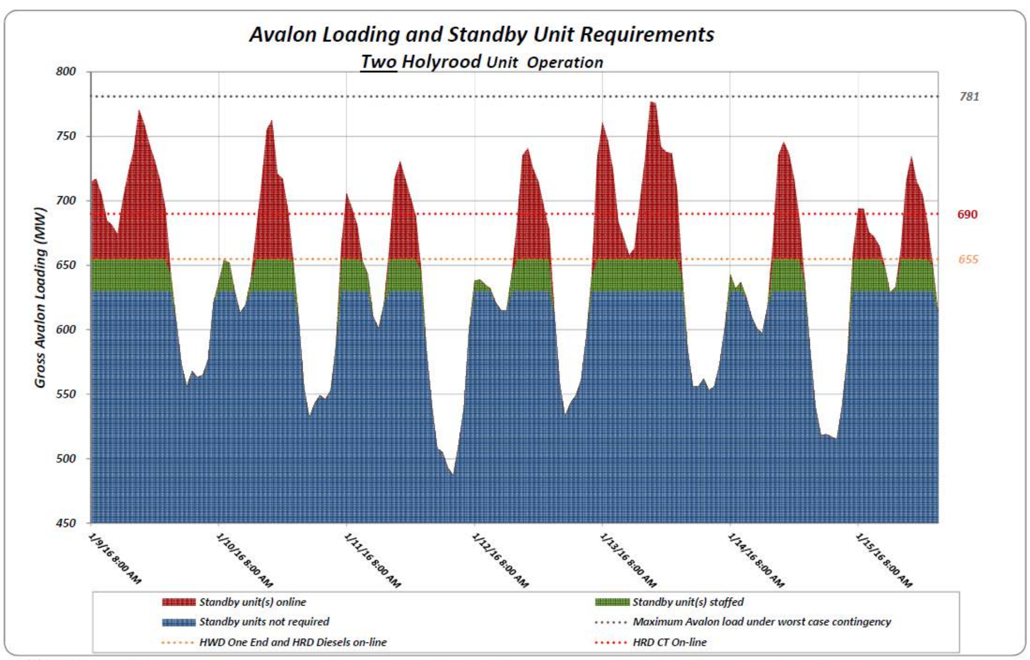
Standby generation was operated throughout this period to support load, as well as Island and Avalon spinning reserve requirements. On January 6, 2016, Holyrood Unit 2 was taken out of service at 04:28 due to boiler tube issues. At the time, Holyrood unit 1 was de-rated to 155 MW.[7] Figures 3 – 10 provide a depiction of the forecast requirement for standby production through this period.

[5] Newfoundland and Labrador Hydro, Supply and Demand Status Report, dated January 6, 2016.



1/9/2016 8:33 Note: This document is for discussion and operational planning and management purposes only. The information contained within is representative within a short time window and may change hourly. All information must be validated by NL Hydro System Operations.

Figure 3: Island spinning reserve forecast January 9-15, 2016



1/9/2016 8:28 Note: This document is for discussion and operational planning and management purposes only. The information contained within is representative within a short time window and may change hourly. All information must be validated by NL Hydro System Operations.

Figure 4: Standby forecast for Avalon reserves January 9-15, 2016

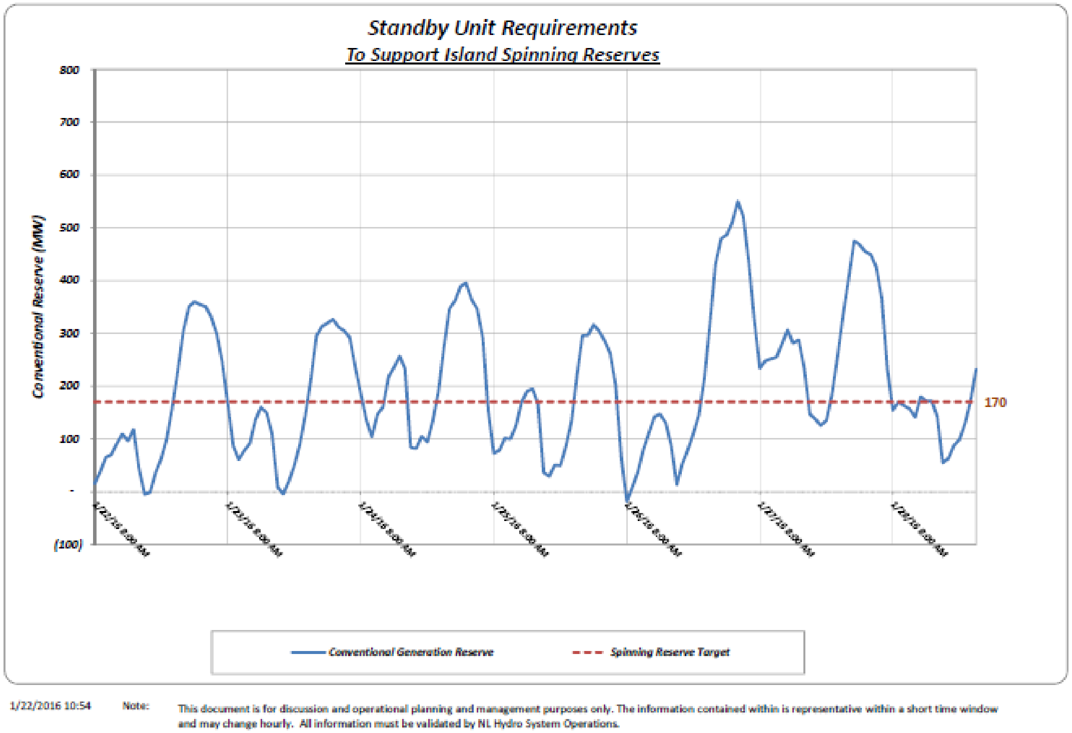


Figure 5: Island spinning reserve forecast January 22-28, 2016

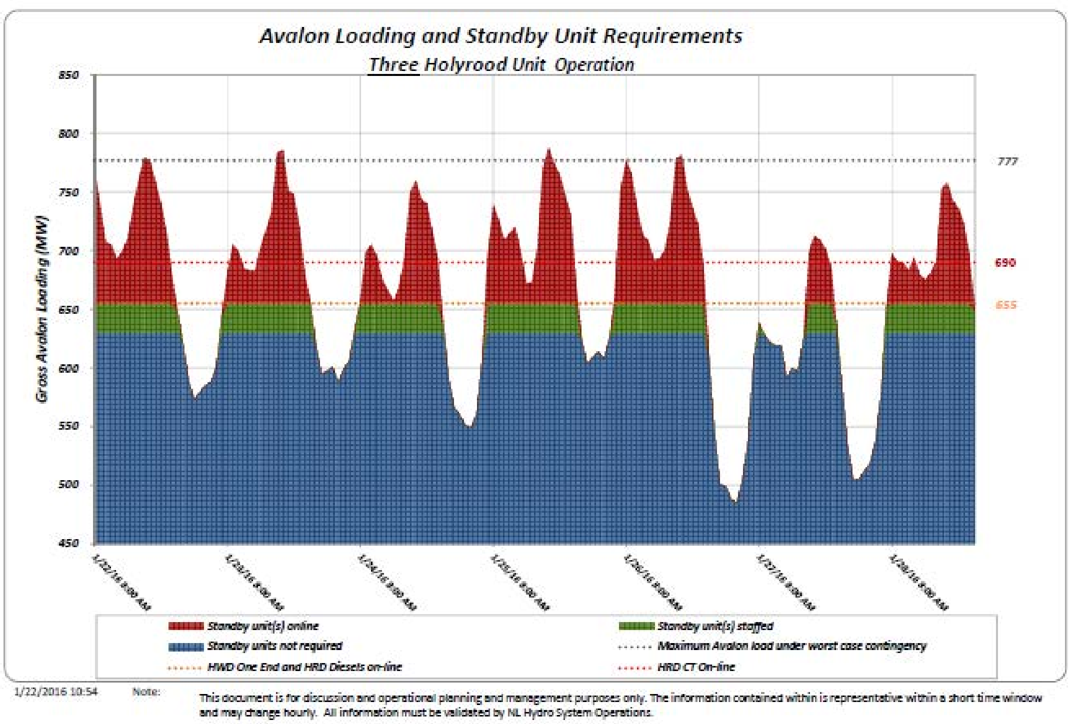


Figure 6: Standby forecast for Avalon reserves January 22-28, 2016

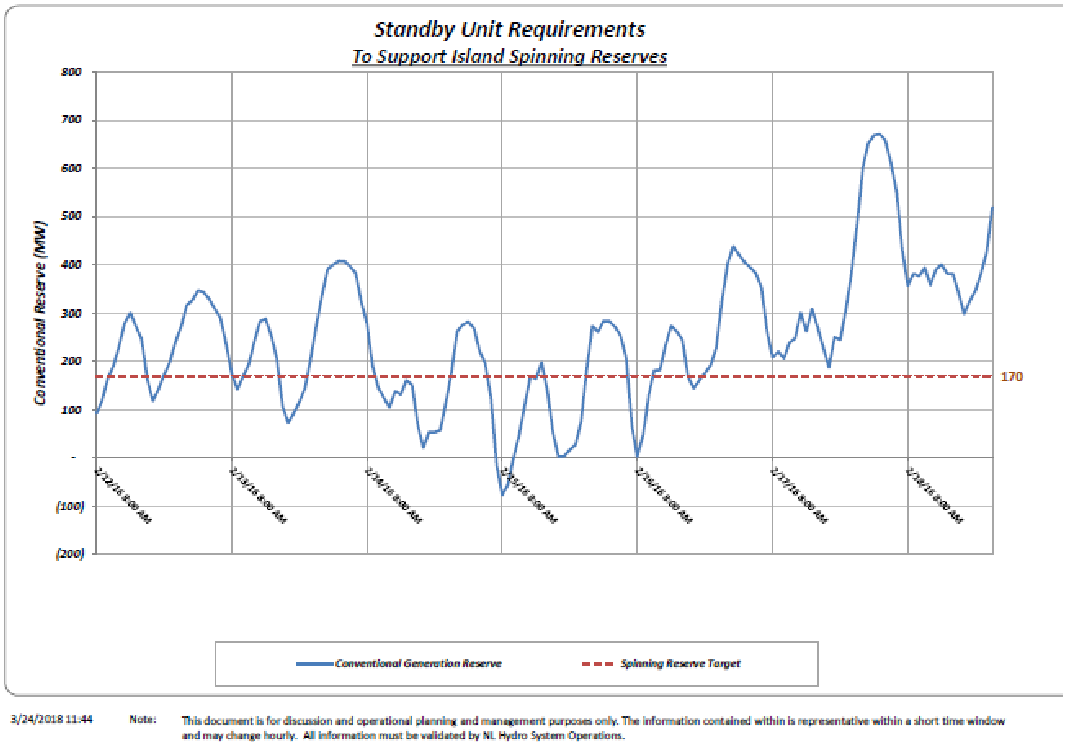


Figure 7: Island spinning reserve forecast February 12-18, 2016

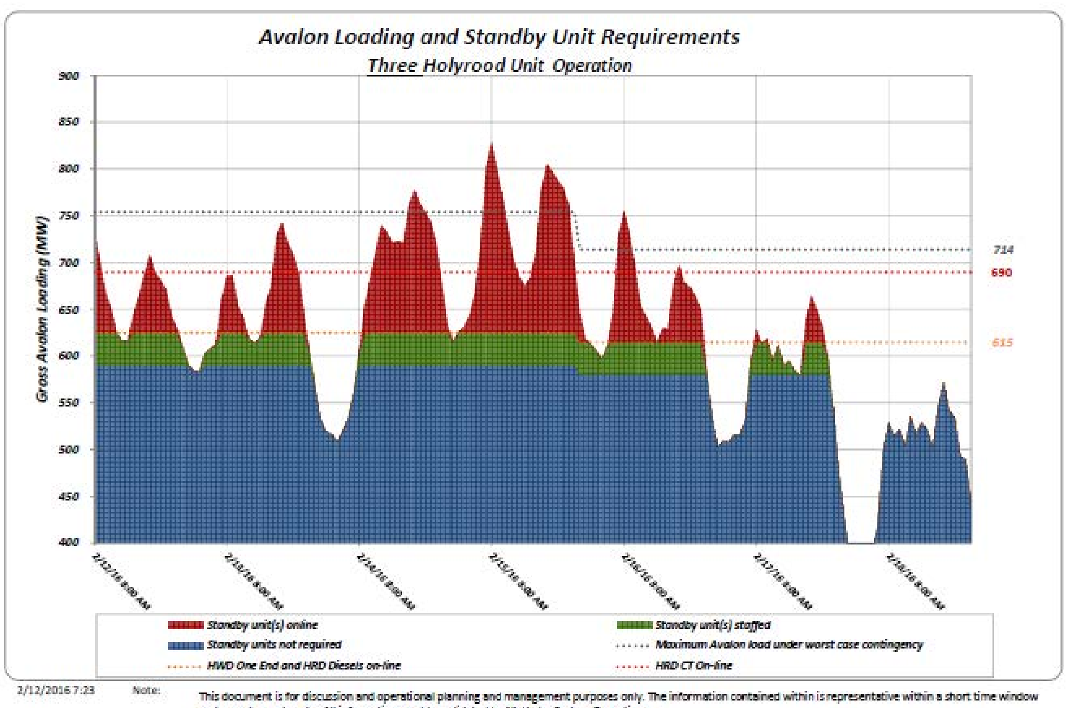
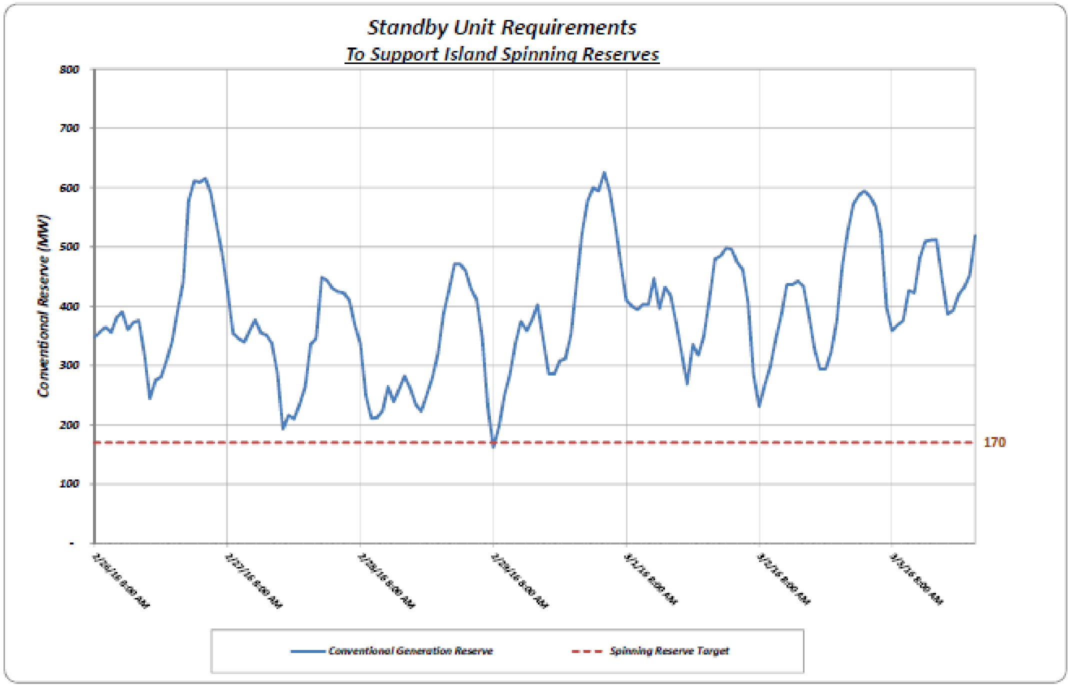


Figure 8: Standby forecast for Avalon reserves February 12-18, 2016



2/26/2016 9:57 Note: This document is for discussion and operational planning and management purposes only. The information contained within is representative within a short time window and may change hourly. All information must be validated by NL Hydro System Operations.

Figure 9: Island spinning reserve forecast February 26-March 3, 2016

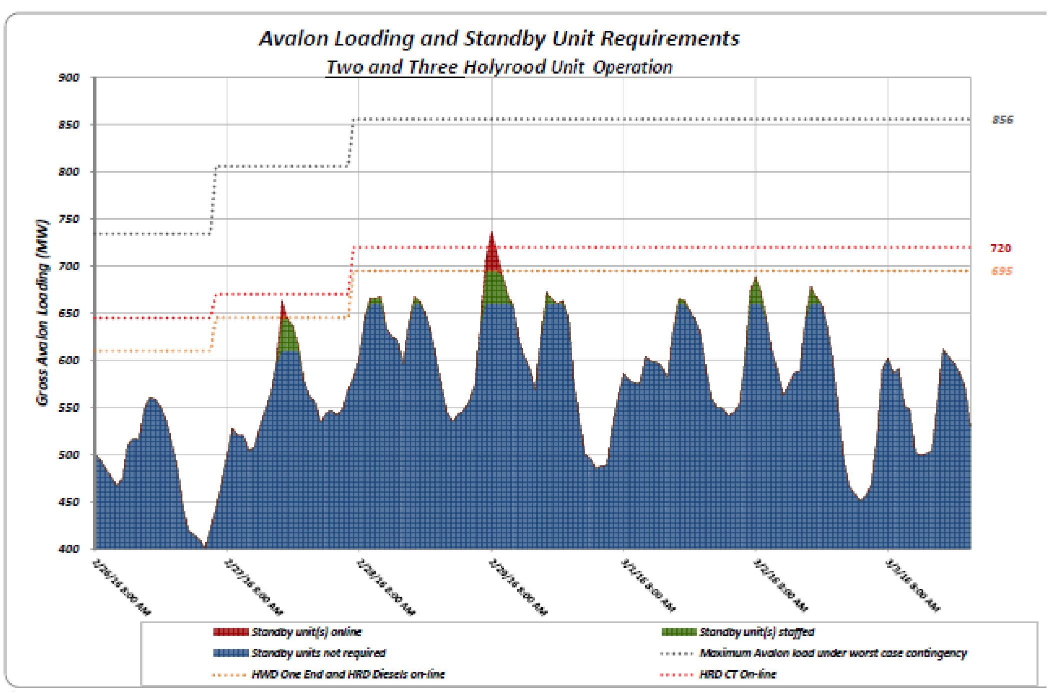


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Figure 10: Standby forecast for Avalon reserves February 26-March 3, 2016

Additionally, thermal generation at Holyrood above minimum unit production began January 4, 2016 to offset hydraulic generation and help conserve water storage in Hydro's reservoirs.

From February 1, 2016 to February 26, 2016, standby generation was also being used to supplement reservoir levels, which were approaching and below system minimum storage targets through the period, as evident in Figure 11.[8] Standby generation was also required at this time due to the continued limitations in availability of Holyrood units. Hydro stopped using thermal generation at Holyrood in support of reservoir levels on April 14, 2016.

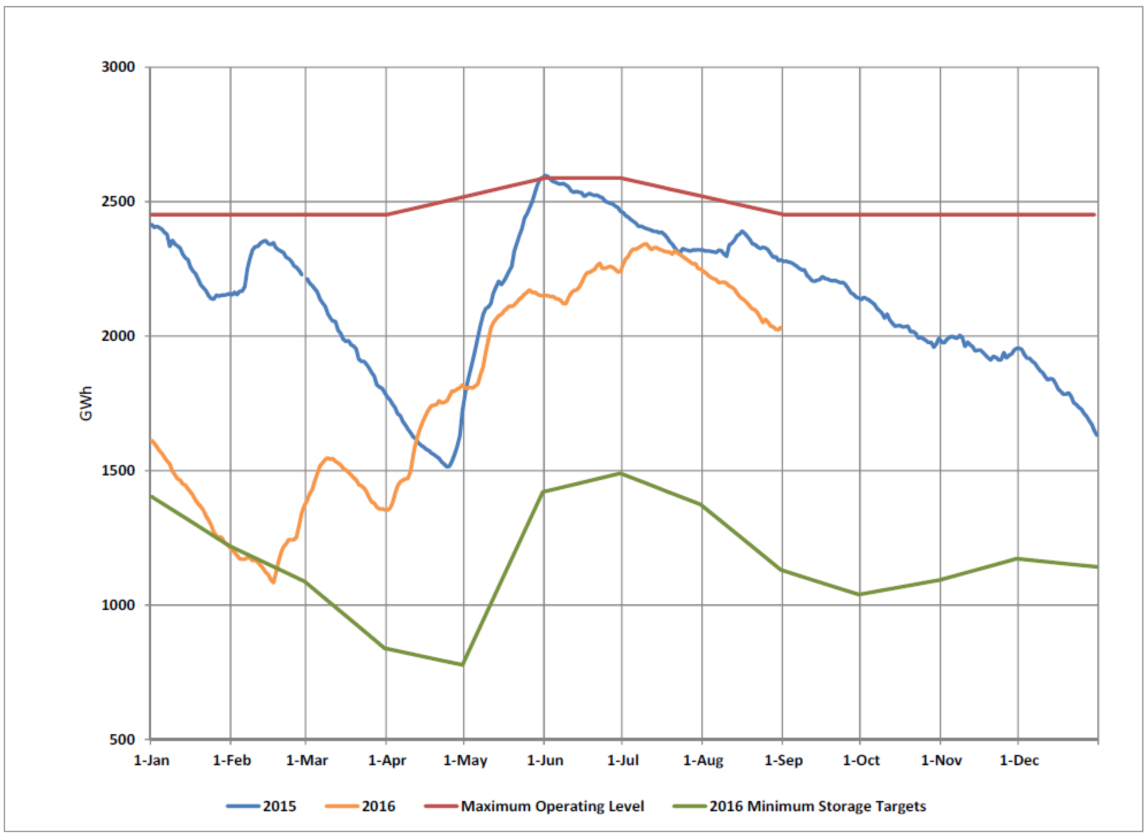
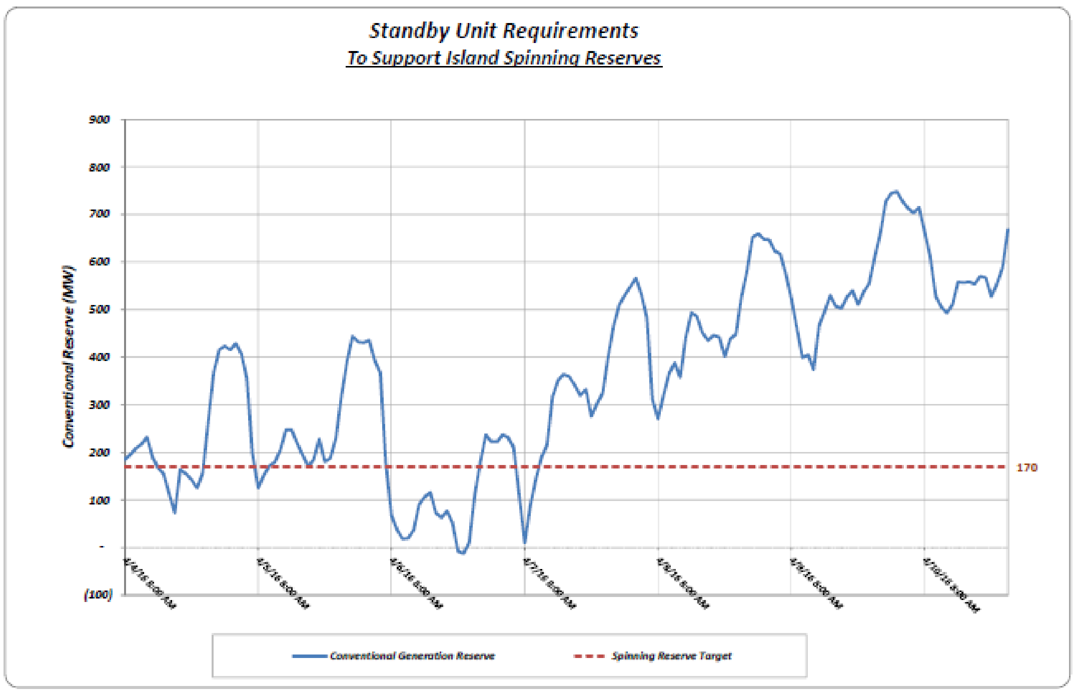


Figure 11: 2016 Minimum Storage Targets as provided in Hydro's first filed Monthly Energy Supply Report – August 2016

[8] Hydro's Energy Supply Report – Monthly Report – August 2016 as filed on September 9, 2016.

Week of April 1, 2016 to April 7, 2016

During this week, standby generation was required from April 4-7, 2016, to support Island and Avalon spinning reserve requirements. During this time the Island system was experiencing unit derating or unit unavailability, totaling 291 MW with Holyrood Units 1 and 2 both de-rated to 120 MW, Hardwoods de-rated to 38 MW, Stephenville End A unavailable at Stephenville, and Bay d'Espoir Units 1 and 2 unavailable.[9]



4/4/2016 7:29 Note: This document is for discussion and operational planning and management purposes only. The information contained within is representative within a short time window and may change hourly. All information must be validated by NL Hydro System Operations.

Figure 12: Island spinning reserve forecast as of April 4-10, 2016

[9] Newfoundland and Labrador Hydro, Supply and Demand Status Reports, dated April 4, 5, 7, and 7, 2016.

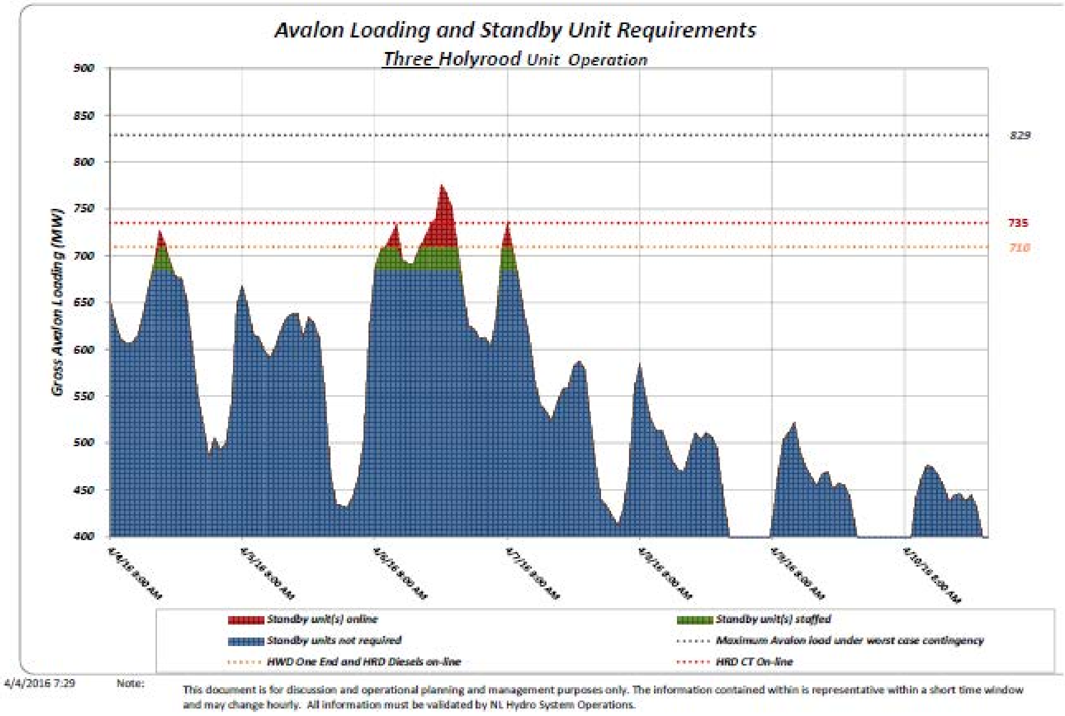
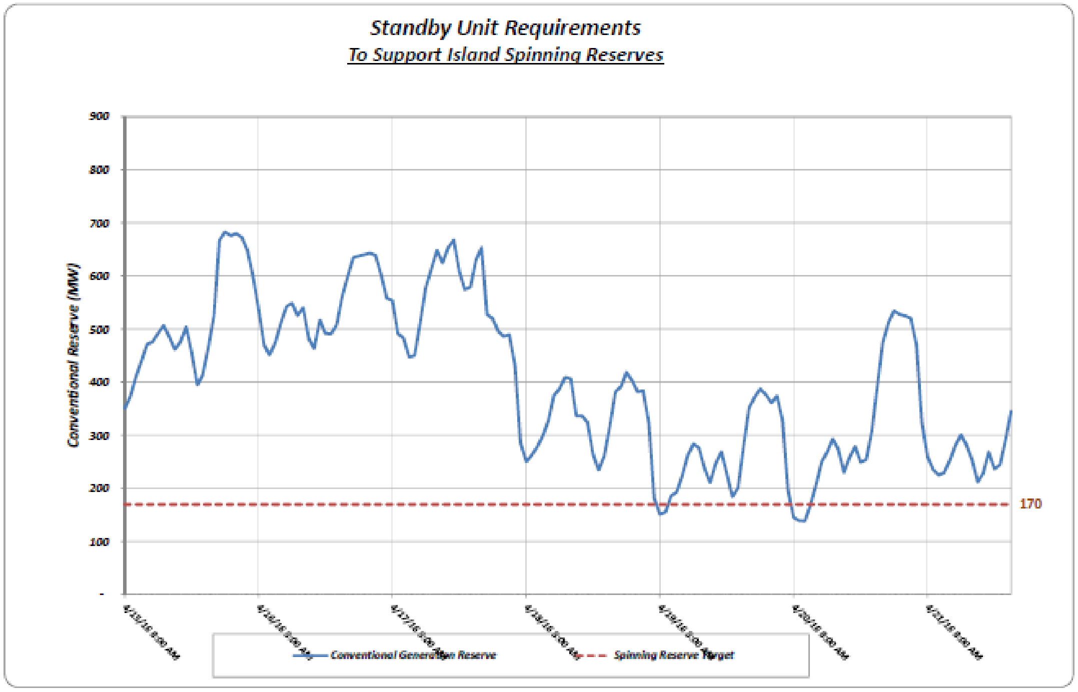


Figure 13: Standby forecast for Avalon reserves as of April 4-10, 2016

Week of April 15, 2016 to April 21, 2016

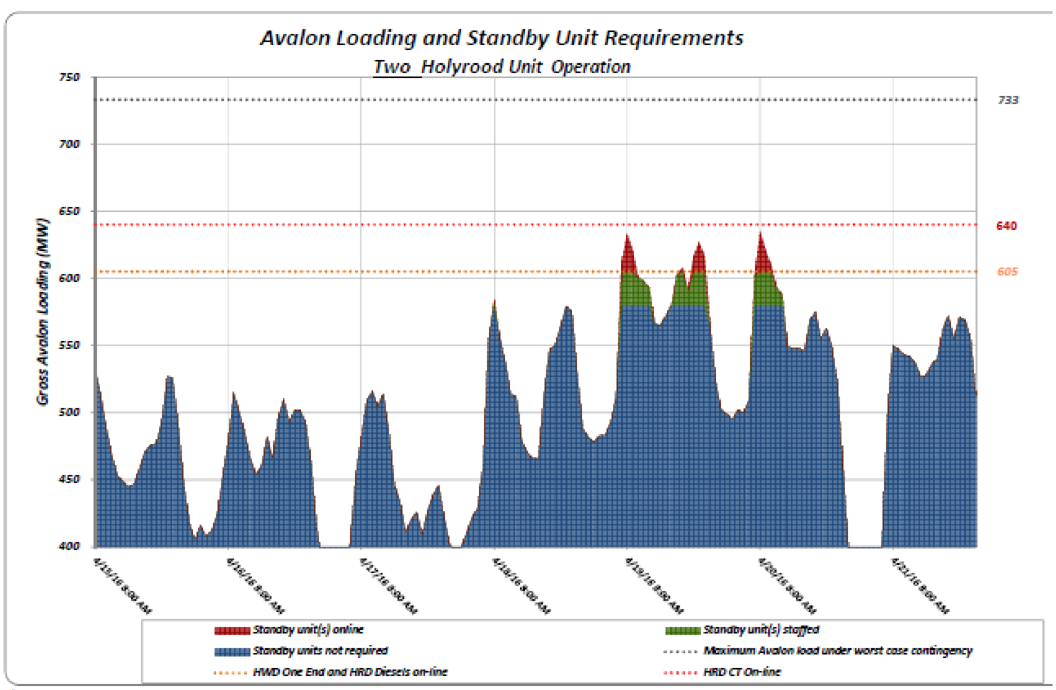
Higher load conditions during this time, with similar generation de-ratings as those experienced in the week of April 1-7, 2016, resulted in the operation of the Holyrood GT on April 18-21, 2016, to support Island and Avalon spinning reserve requirements. In addition to the de-ratings experienced earlier in April, which persisted through this period, Holyrood Unit 3 was also unavailable during this time.[10]

[10] Newfoundland and Labrador Hydro, Supply and Demand Status Reports, dated April 18, 19, 20, and 21 2016.



4/15/2016 7:43 Note: This document is for discussion and operational planning and management purposes only. The information contained within is representative within a short time window and may change hourly. All information must be validated by NL Hydro System Operations.

Figure 14: Island spinning reserve forecast as of April 15-21, 2016

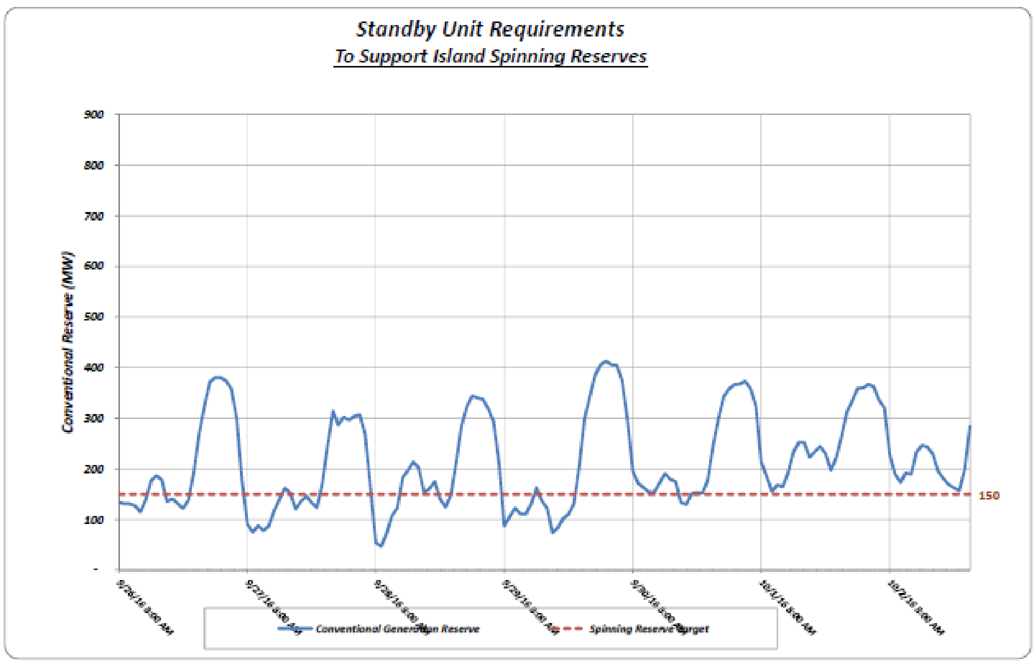


4/15/2016 8:47 Note: This document is for discussion and operational planning and management purposes only. The information contained within is representative within a short time window and may change hourly. All information must be validated by NL Hydro System Operations.

Figure 15: Standby forecast for Avalon reserves as of April 15-21, 2016

Week of September 26, 2016 to October 2, 2016

During this week, standby generation was required to support Island spinning reserves and facilitate a planned outage to transmission line TL 237 from September 26-29, 2016. Hydro's reserve assessments determined that during this period the unit was required in order to protect against the contingency of a loss of a Holyrood unit and to maintain the system within static and dynamic limits, post-contingency. At the time, both Holyrood Units 1 and 3 were offline for planned maintenance. Holyrood Unit 2 was online, de-rated to 130 MW.[11] The planned outage for transmission line TL 237 was completed on September 30, 2016, following which the Holyrood GT was no longer required to support spinning reserves.



9/26/2016 10:16 Note: This document is for discussion and operational planning and management purposes only. The information contained within is representative within a short time window and may change hourly. All information must be validated by NL Hydro System Operations.

Figure 16: Island spinning reserve forecast as of September 26-October 2, 2016

[11] Newfoundland and Labrador Hydro, Supply and Demand Status Reports, dated September 26, 27, 28, and 29 2016.

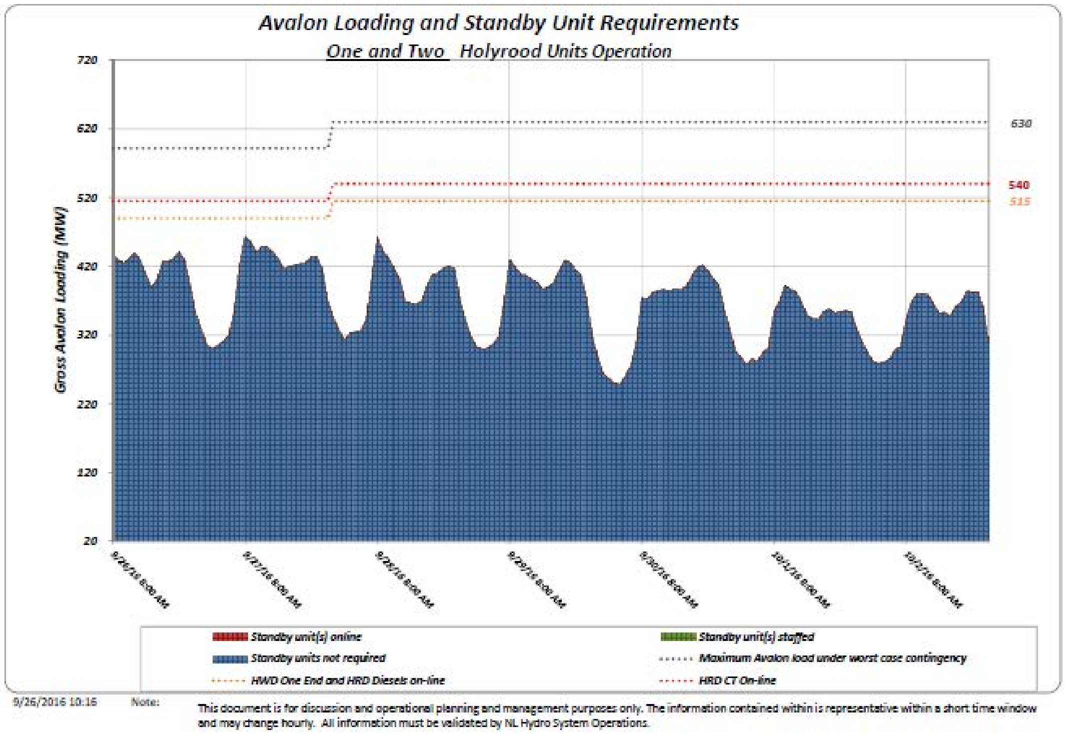


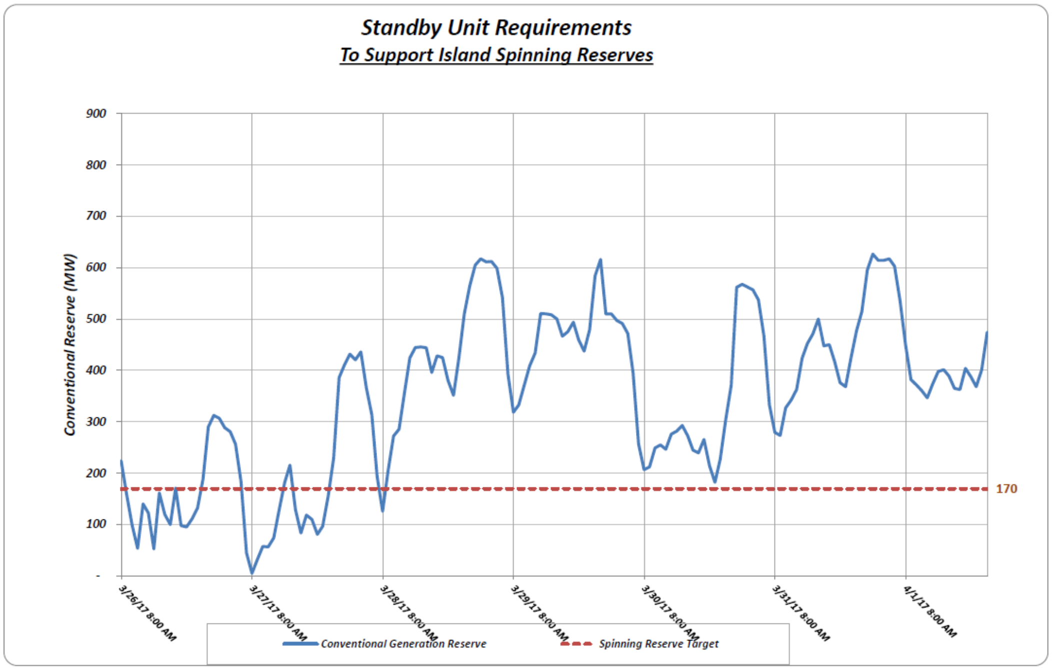
Figure 17: Standby forecast for Avalon reserves as of September 26-October 2, 2016

Specific Examples of Standby Generation Required in 2017

Week of March 26, 2017 to April 1, 2017

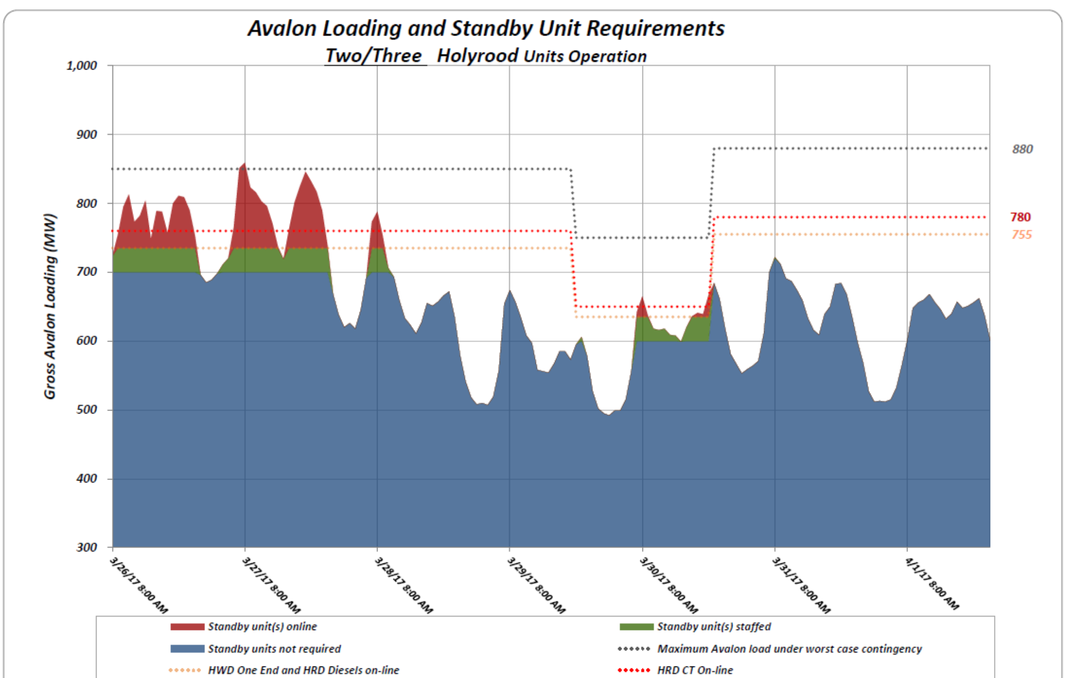
During this week, standby generation was required to support both Avalon and Island spinning reserves. At the time, both Holyrood Units 1 and 2 were de-rated to 120 MW.[12]

[12] Newfoundland and Labrador Hydro, Supply and Demand Status Report, dated March 26, 2016.



3/26/2017 7:45 Note: This document is for discussion and operational planning and management purposes only. The information contained within is representative within a short time window and may change hourly. All information must be validated by NL Hydro System Operations.

Figure 18: Island spinning reserve forecast as of March 26-April 2, 2017

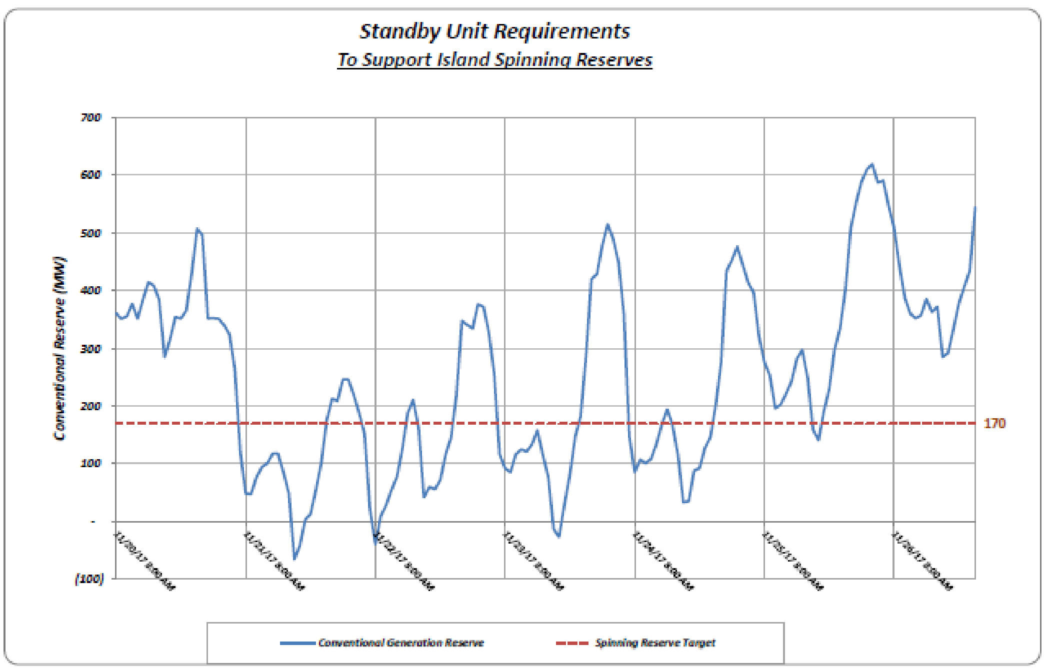


This document is for discussion and operational planning and management purposes only. The information contained within is representative within a short time window and may change hourly. All information must be validated by NL Hydro System Operations.

Figure 19: Standby forecast for Avalon reserves as of March 26-April 2, 2017

Week of November 19, 2017 to November 25, 2017

During this week, standby generation was required to support Avalon and Island spinning reserves on November 19, 2017 and November 21-24, 2017. Holyrood Unit 3 became unavailable on November 19, 2017 at 0624. As such, the Holyrood GT was operated for the evening peak on November 19, 2017. Holyrood Unit 3 was returned to service at 0227 on November 20, 2017. On November 20, 2017 at 2115, Holyrood Unit 2 was taken out of service to repair a safety valve and replace exciter card. The Holyrood GT was operated as required to support spinning reserves until Unit 2 was returned to service at 1908 on November 24, 2017.[13]



11/20/2017 10:03 Note: This document is for discussion and operational planning and management purposes only. The information contained within is representative within a short time window and may change hourly. All information must be validated by NL Hydro System Operations.

Figure 20: Island spinning reserve forecast as of November 20-26, 2017

[13] Newfoundland and Labrador Hydro, Supply and Demand Status Reports, dated November 19, 20, and 25 2017.

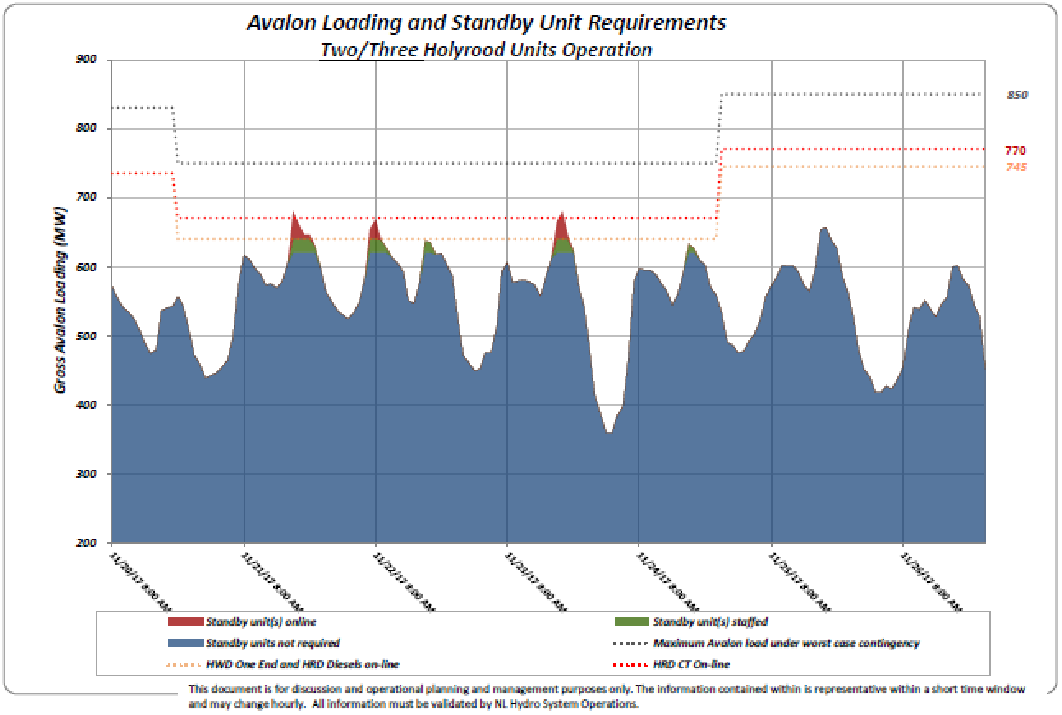
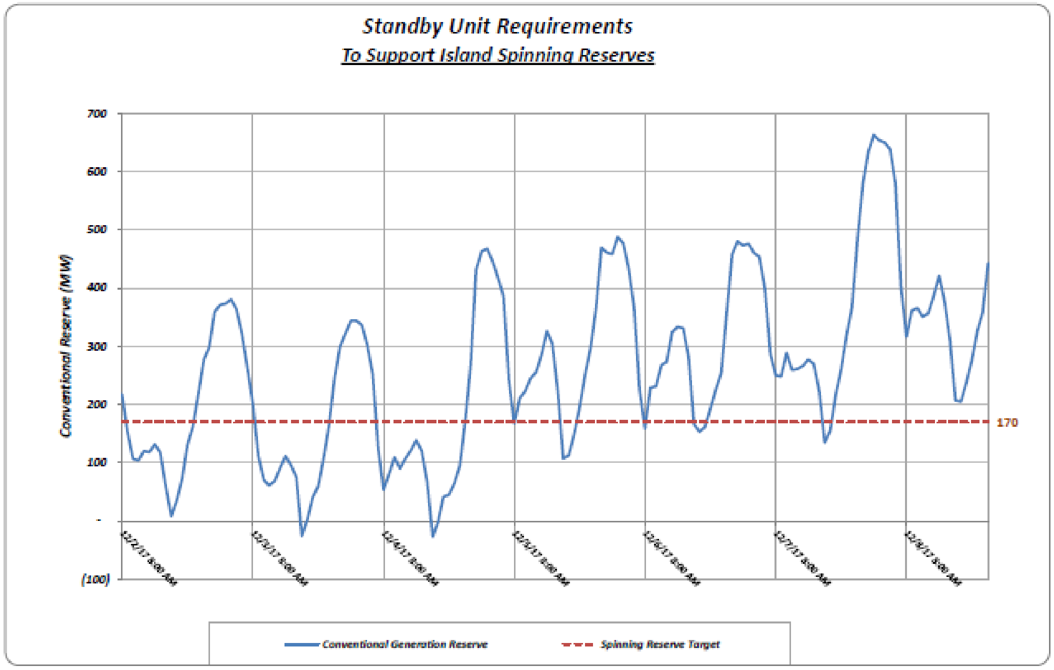


Figure 21: Standby generation forecast for Avalon reserves as of November 20-26, 2017

Week of December 3, 2017 to December 9, 2017

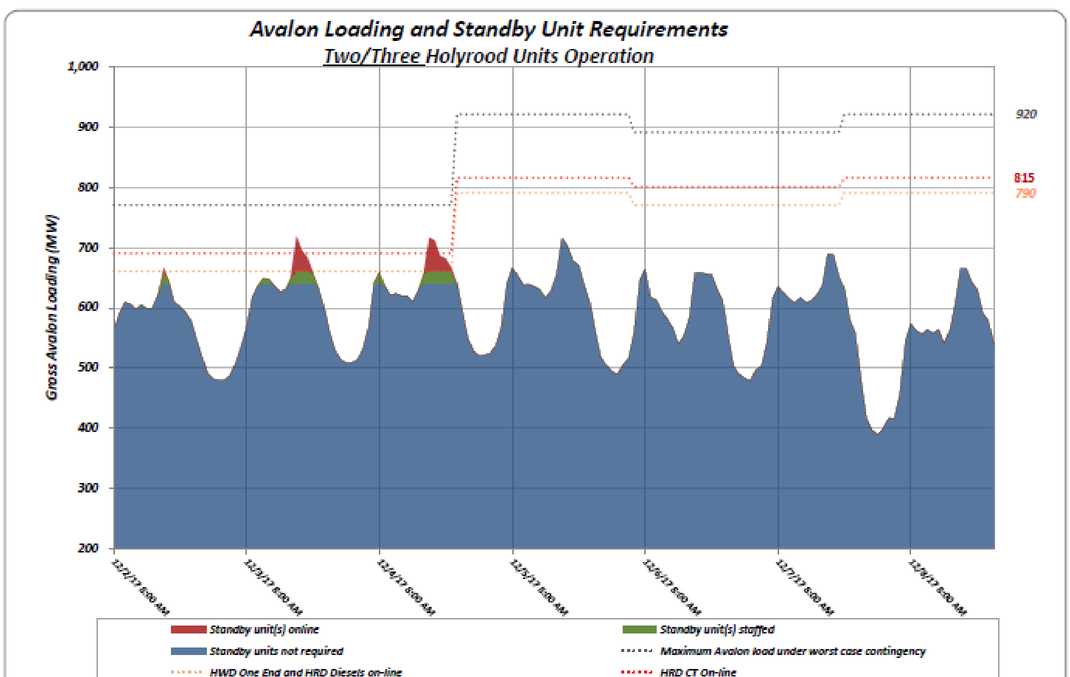
During this week, standby generation was required to support Avalon and Island spinning reserves on December 3-6, 2017, as required. Holyrood Unit 1 was offline through December 4, 2017 for an air heater wash. The unit returned to service on December 4, 2017 at 1508 hours. Through this period, Bay d'Espoir Units 1 and 2 were unavailable due to issues with the common penstock.[14]

[14] Newfoundland and Labrador Hydro, Supply and Demand Status Report, dated December 4, 2017.



12/2/2017 7:12 Note: This document is for discussion and operational planning and management purposes only. The information contained within is representative within a short time window and may change hourly. All information must be validated by NL Hydro System Operations.

Figure 22: Island spinning reserve forecast as of December 2-8, 2017



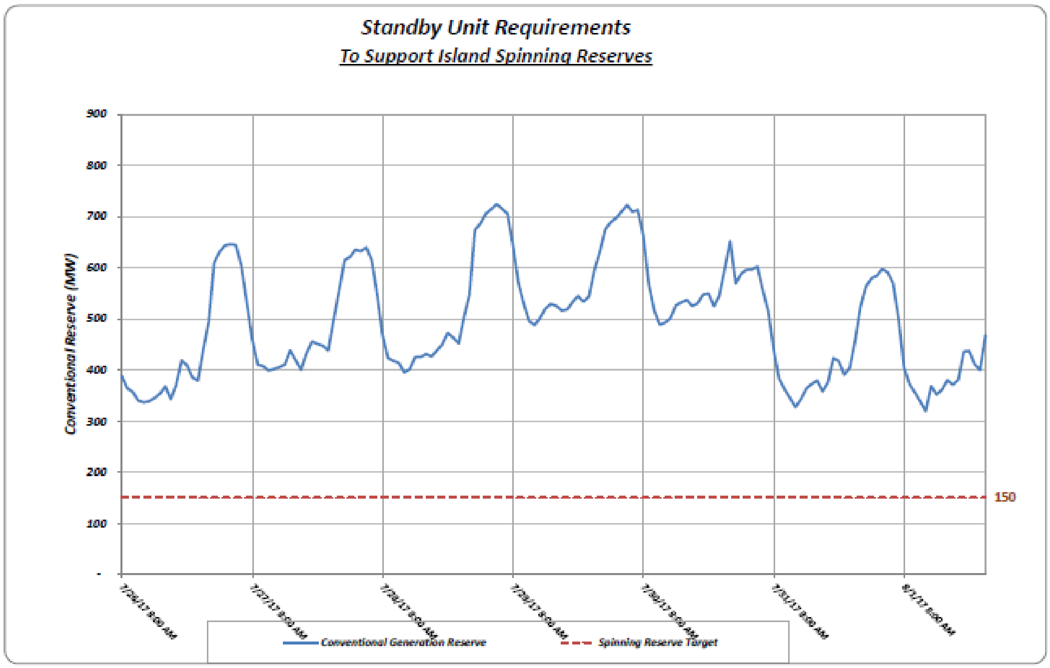
This document is for discussion and operational planning and management purposes only. The information contained within is representative within a short time window and may change hourly. All information must be validated by NL Hydro System Operations.

Figure 23: Standby generation forecast for Avalon reserves as of December 2-8, 2017

Period from July 31' 2017 to August 18, 2017

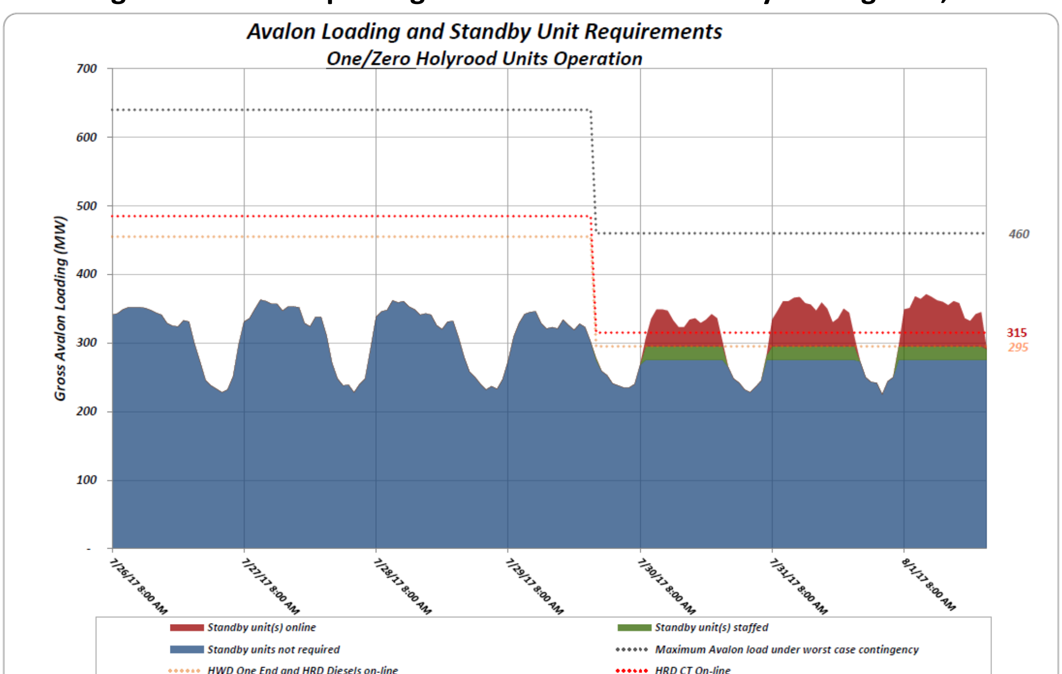
During this period, standby generation was required to support Avalon reserves given that the Holyrood plant was unavailable due to a scheduled total plant outage.[15] A total plant outage was required to perform maintenance on systems that support all three generating units. These common systems cannot be safely maintained unless all units are placed out of service.

[15] Newfoundland and Labrador Hydro, Supply and Demand Status Reports, dated August 1 and 24, 2017.



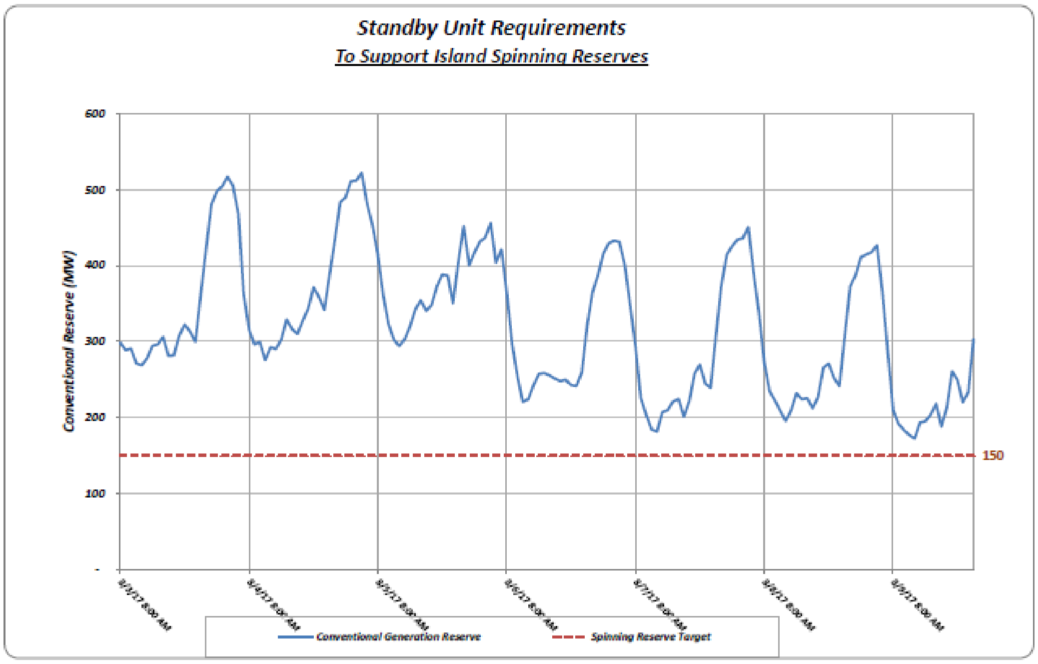
7/26/2017 6:26 Note: This document is for discussion and operational planning and management purposes only. The information contained within is representative within a short time window and may change hourly. All information must be validated by NL Hydro System Operations.

Figure 24: Island spinning reserve forecast as of July 26-August 1, 2017



This document is for discussion and operational planning and management purposes only. The information contained within is representative within a short time window and may change hourly. All information must be validated by NL Hydro System Operations.

Figure 25: Standby generation forecast for Avalon reserves as of July 26-August 1, 2017



8/3/2017 9:24 Note: This document is for discussion and operational planning and management purposes only. The information contained within is representative within a short time window and may change hourly. All information must be validated by NL Hydro System Operations.

Figure 26: Island spinning reserve forecast as of August 3-9, 2017

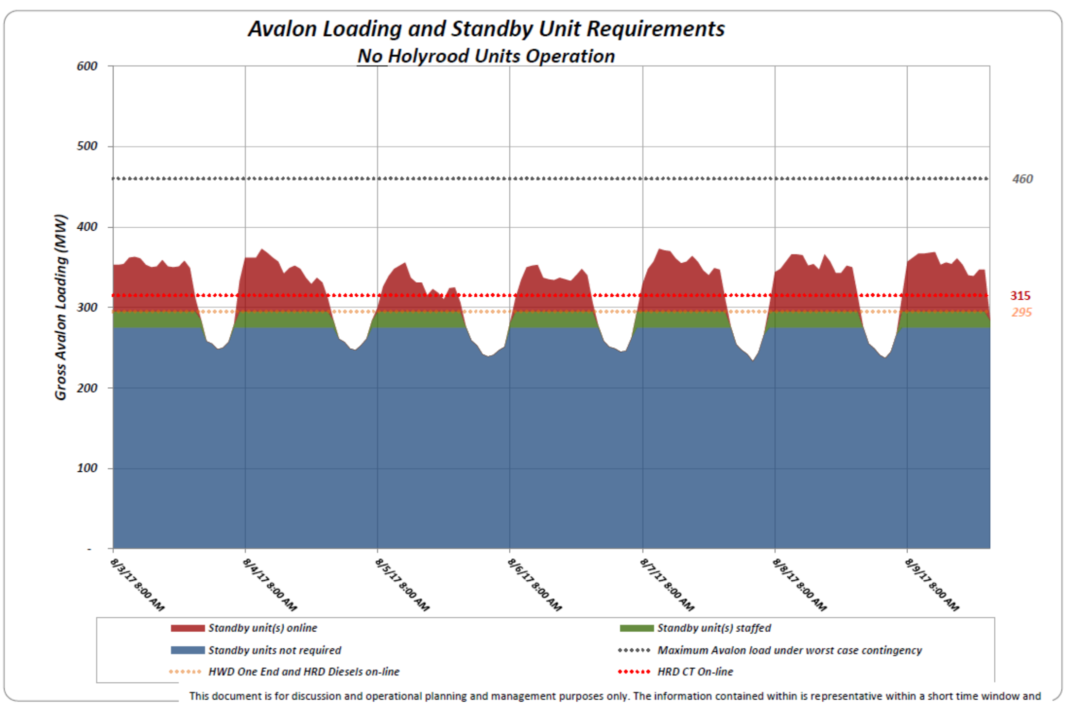
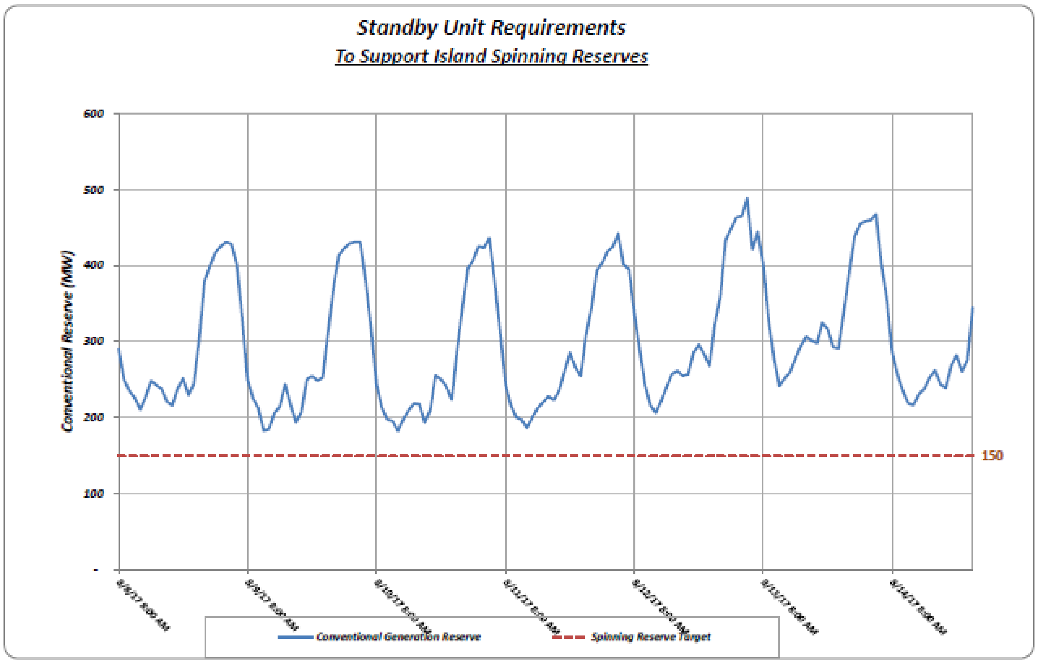
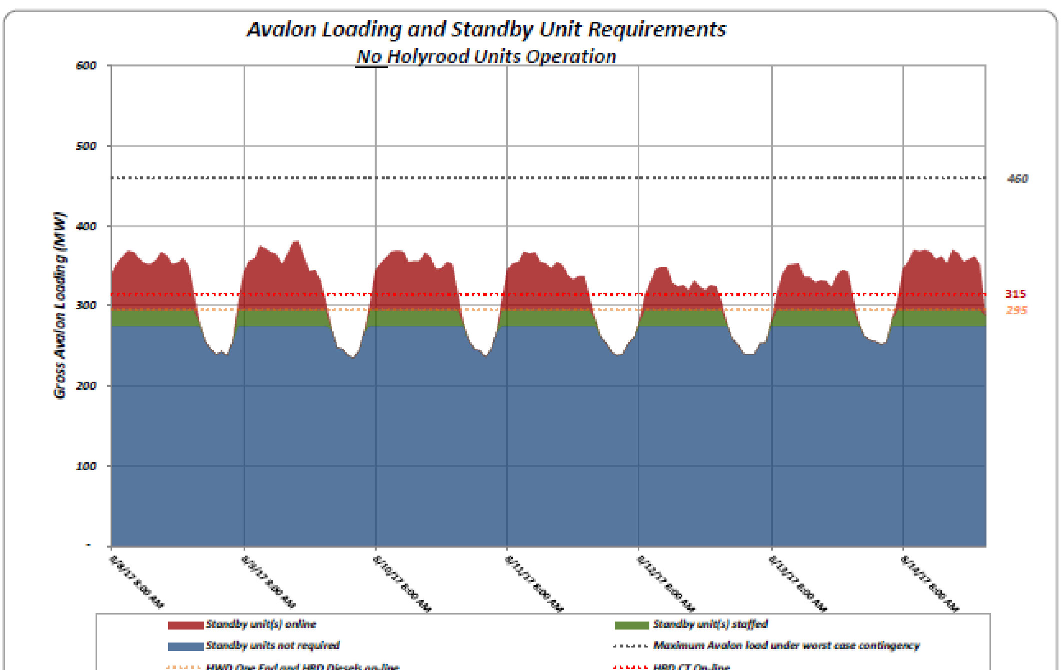


Figure 27: Standby generation forecast for Avalon reserves as of August 3-9, 2017



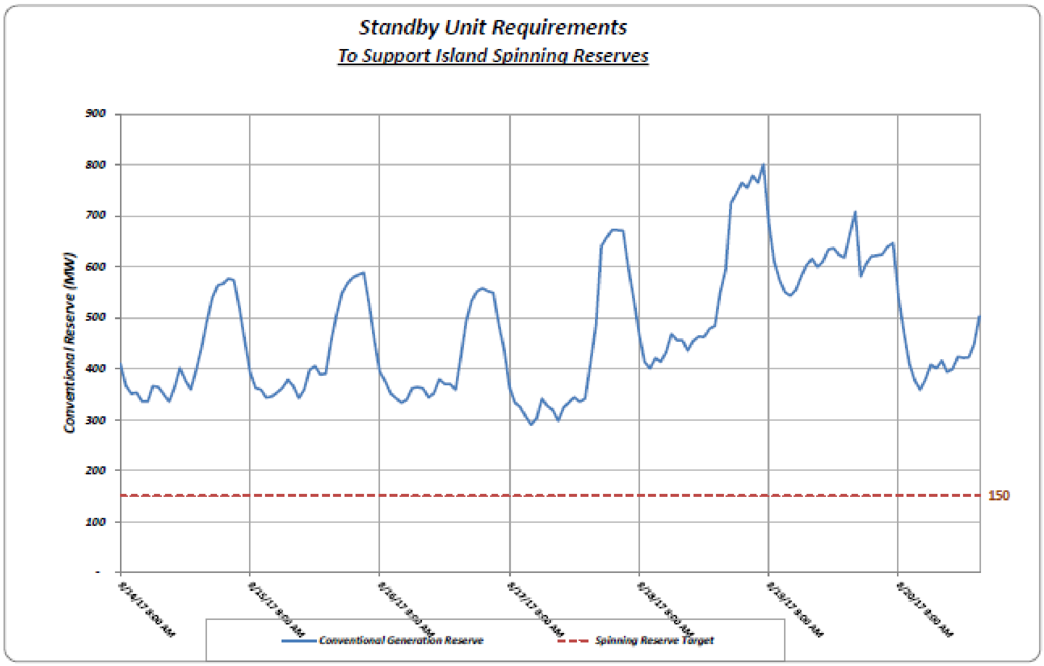
8/8/2017 6:22 Note: This document is for discussion and operational planning and management purposes only. The information contained within is representative within a short time window and may change hourly. All information must be validated by NL Hydro System Operations.

Figure 28: Island spinning reserve forecast as of August 8-14, 2017



This document is for discussion and operational planning and management purposes only. The information contained within is representative within a short time window and may change hourly. All information must be validated by NL Hydro System Operations.

Figure 29: Standby generation forecast for Avalon reserves as of August 8-14, 2017



8/14/2017 7:06 Note: This document is for discussion and operational planning and management purposes only. The information contained within is representative within a short time window and may change hourly. All information must be validated by NL Hydro System Operations.

Figure 30: Island spinning reserve forecast as of August 14-20, 2017

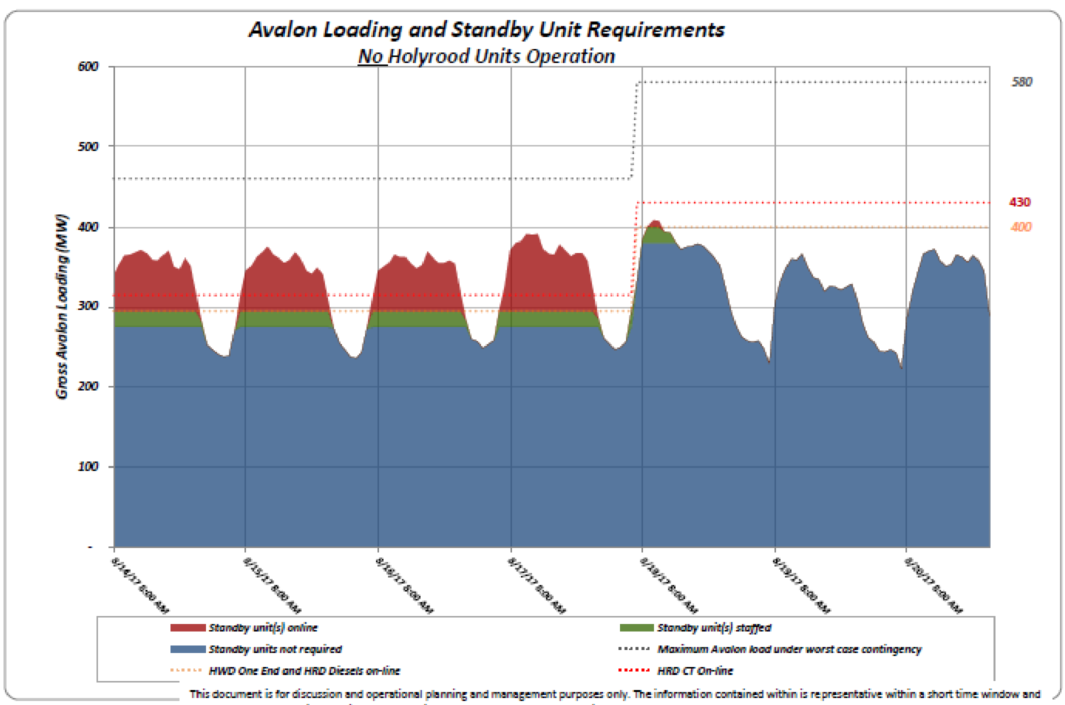


Figure 31: Standby generation forecast for Avalon reserves as of August 14-20, 2017

Appendix C
2015 Isolated Systems Deferral

2015 Isolated Systems Supply Cost Variance Account
December 31, 2015

Particulars	Diesel	HQ Purchases	Other [1]	Total
A - 2015 Actual Supply Produced & Purchased (kWh)	51,676,533	24,578,740	646,064	76,901,337
B - 2015 Actual Cost / 2017 Actual Produced & Purchased ($/kWh) [B1 / B2]	0.31401	0.10898	0.25652	0.2480
C - 2015 Test Year Cost / 2015 Test Year Produced & Purchased ($/kWh) [C1 / C2]	0.30014	0.11341	0.25629	0.2459
Isolated Supply Costs [A x (B-C)]				163,031
Cost Variance Threshold				500,000
Isolated Systems Supply Cost Deferral Balance				-
B1 - 2015 Actual Cost of No. 2 Fuel + Purchases ($)	16,226,822	2,678,557	165,726	19,071,106
B2 - 2015 Actual Supply Produced & Purchased (kWh)	51,676,533	24,578,740	646,064	76,901,337
C1 - 2015 Test Year Cost of No. 2 Fuel + Purchases ($)	17,122,665	2,657,829	202,468	19,982,962
C2 - 2015 Test Year Supply Produced & Purchased (kWh)	57,048,141	23,435,400	790,000	81,273,541

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

Appendix D
2016 Isolated Systems Deferral

2016 Isolated Systems Supply Cost Variance Account
December 31, 2016

Particulars	Diesel	HQ Purchases	Other [1]	Total
A - 2016 Actual Supply Produced & Purchased (kWh)	51,276,280	26,142,980	610,667	78,029,927
B - 2016 Actual Cost / 2017 Actual Produced & Purchased ($/kWh) [B1 / B2]	0.27292	0.09054	0.22558	0.21144
C - 2015 Test Year Cost / 2015 Test Year Produced & Purchased ($/kWh) [C1 / C2]	0.30014	0.11341	0.25629	0.24587
Isolated Supply Costs [A x (B-C)]				(2,686,570)
Cost Variance Threshold				(500,000)
Isolated Systems Supply Cost Deferral Balance				**(2,186,570)**
B1 - 2016 Actual Cost of No. 2 Fuel + Purchases ($)	13,994,229	2,367,050	137,752	16,499,031
B2 - 2016 Actual Supply Produced & Purchased (kWh)	51,276,280	26,142,980	610,667	78,029,927
C1 - 2015 Test Year Cost of No. 2 Fuel + Purchases ($)	17,122,665	2,657,829	202,468	19,982,962
C2 - 2015 Test Year Supply Produced & Purchased (kWh)	57,048,141	23,435,400	790,000	81,273,541

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

Appendix E
2017 Isolated Systems Deferral

Isolated Systems Supply Cost Variance Account
December 31, 2017

Particulars	Diesel	HQ Purchases	Other [1]	Total
A - 2017 Actual Supply Produced & Purchased (kWh)	49,994,742	24,802,850	569,235	75,366,827
B - 2017 Actual Cost / 2017 Actual Produced & Purchased ($/kWh) [B1 / B2]	0.28318	0.10580	0.24985	0.22455
C - 2015 Test Year Cost / 2015 Test Year Produced & Purchased ($/kWh) [C1 / C2]	0.30014	0.11341	0.25629	0.24587
Isolated Supply Costs [A x (B-C)]				(1,606,821)
Cost Variance Threshold				(500,000)
Isolated Systems Supply Cost Deferral Balance				**(1,106,821)**
B1 - 2017 Actual Cost of No. 2 Fuel + Purchases ($)	14,157,439	2,624,155	142,223	16,923,818
B2 - 2017 Actual Supply Produced & Purchased (kWh)	49,994,742	24,802,850	569,235	75,366,827
C1 - 2015 Test Year Cost of No. 2 Fuel + Purchases ($)	17,122,665	2,657,829	202,468	19,982,962
C2 - 2015 Test Year Supply Produced & Purchased (kWh)	57,048,141	23,435,400	790,000	81,273,541

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

Appendix F
2015 Rural Deficit Report

A REPORT TO
THE BOARD OF COMMISSIONERS OF PUBLIC UTILITIES
(pursuant to Order No. P.U. 14(2004))

RURAL DEFICIT ANNUAL REPORT
Summary of Specific Initiatives

NEWFOUNDLAND AND LABRADOR HYDRO

March 2016

Revised August 3, 2017

newfoundland labrador hydro
a nalcor energy company

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1 Introduction

Newfoundland and Labrador Hydro (Hydro) serves approximately 38,300 Rural Customers. Electrical service is provided to the majority of these customers at an operating loss or deficit, except for the approximately 11,000 Rural Customers served on the Labrador Interconnected System who pay rates which both recover costs as well as contribute to funding a portion of the rural deficit.

While there is no cost of service available by each diesel area or community, revenues from Rural Customers, particularly diesel areas, do not fully offset fixed costs. Therefore, the incremental cost of fuel is a direct impact to the rural deficit as it is not fully recovered from revenues from sales.

Hydro's mandate to provide least-cost, safe and reliable power to all its customers remains its primary focus. One of several measures Hydro uses to control its operating expenses are internal and customer Conservation and Demand Management (CDM) initiatives. Such efforts reduce Hydro's costs and assist in reducing and/or limiting the growth of overall system fuel costs.

2 Rural Deficit Overview

Table 1 below shows the rural deficit for 2011 to 2015, excluding Labrador Interconnected. The 2014 Rural Deficit is estimated based upon the 2014 actual costs combined with a portion of the $45.9 million deferred 2014 Revenue Deficiency allocated to the rural deficit. The 2015 Rural Deficit calculation is based on the 2015 Test Year Cost of Service for 2015 Revenue Deficiency as filed in Hydro's May 18, 2017 Compliance Rates Application, updated for revenue to reflect actual revenues and operating costs. This information was filed with the Board during the Amended 2013 GRA process on May 18, 2017.

Operating expenses have increased from $40.0 million in 2011 to $53.6 million in 2015, primarily driven by increases in wages and benefits as well as increases in maintenance and material costs due to investment in aging assets.

Table 1
Hydro Rural (Excluding Labrador Interconnected)

$000,000	Annual Amounts					Year over Year			
	2011	2012	2013	2014	2015	2012/ 2011	2013/ 2012	2014/ 2013	2015/ 2014
Revenues	58.4	60.8	62.5	62.6	63.2	2.4	1.7	0.1	0.6
Costs:									
Operating Expenses	40.0	43.0	44.4	47.4	53.6	3.0	1.4	3.0	6.2
Fuel	26.1	27.6	28.9	35.7	26.8	1.5	1.2	6.8	(8.9)
Purchased Power	7.0	7.5	7.7	7.9	7.3	0.4	0.2	0.2	(0.6)
Depreciation	14.2	11.6	12.5	12.7	14.2	(2.6)	0.9	0.2	1.5
Return[1]	20.5	20.4	19.7	23.0	24.8	(0.1)	(0.7)	3.3	1.8
Total	107.8	110.1	113.1	126.7	126.7	2.3	3.1	13.5	0.0
Rural Deficit	**49.4**	**49.3**	**50.6**	**64.1**	**63.5**	**(0.1)**	**1.4**	**13.4**	**(0.6)**

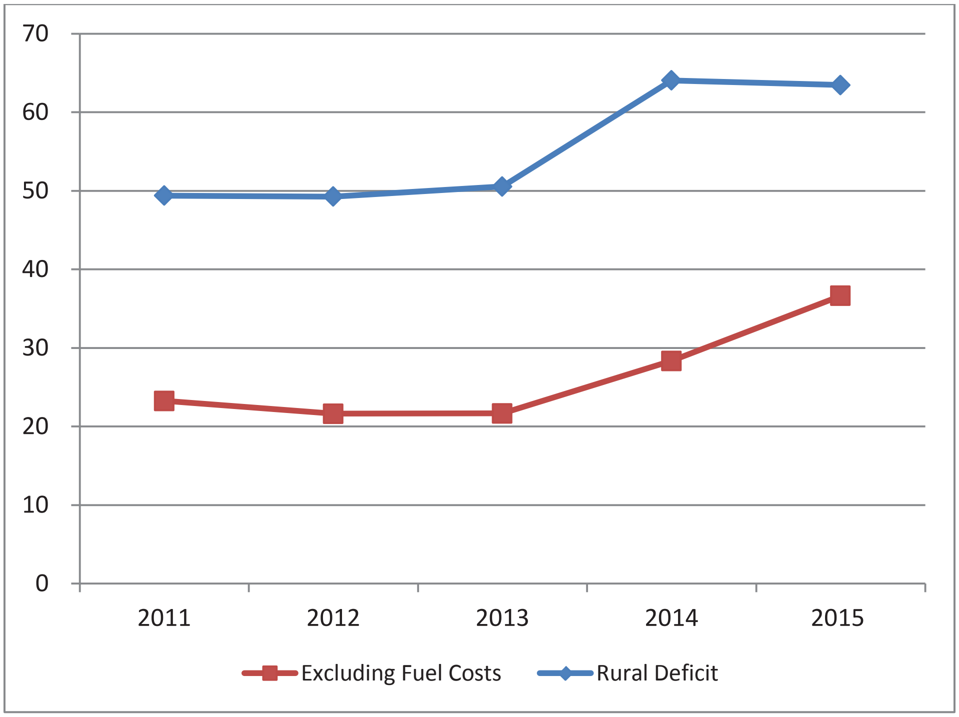
Table 1 above shows the overall rural deficit of $63.5 million in 2015 was lower than 2014 by approximately $0.6 million or 0.9%, primarily due to increased revenues. Costs were flat year-over year with a $9.5 million decrease in fuel and purchased power expenses, which were [] offset by an increase in operating expenses, depreciation, and return.

[1] Reflects return on debt only, for 2012 – 2013 inclusive.

Chart 1 below presents the rural deficit excluding and including fuel costs for the period 2011 to 2015.

Chart 1

Five-Year Rural Deficit ($ millions)



The rural deficit has been relatively consistent year over year for the period 2010 to 2013 when the impact of fuel costs is excluded. For 2014, the increased rural deficit (excluding fuel) reflects the inclusion of 8.8% return on equity proposed for rural assets. The $8.9 million decrease in the fuel expense from 2014 to 2015 reflects the increase shown when fuel costs are excluded.

3 Operating Initiatives

3.1 Internal Energy Efficiency Initiatives

In 2008, Hydro raised its focus on improving internal efficiency to reduce the internal use of energy. This ongoing activity is targeting reductions in energy usage in all facilities including diesel plants, offices, and line depots within the areas affecting the rural deficit. In 2015, Hydro completed or launched operating initiatives that are part of multi-year projects through its internal energy efficiency program. Such initiatives contribute to overall cost containment, a portion of which is allocated to Rural Customers and therefore contributes to deficit reduction. Initiatives completed in 2015 include:

- Installation of automatic temperature set-back controls for space heaters in three buildings (Whitbourne Garage, Port Saunders Line Shop, and Quartzite Control Bldg);
- Inefficient lighting at the Ramea engine hall was replaced with LED fixtures;
- Continuing to replace inefficient interior and exterior fixtures with more efficient LED fixtures at Bay d'Espoir, along with installing more efficient controls for heaters;
- The compressed air system at the Bay d'Espoir plant was re-designed, and a new efficient compressor installed to reduce energy waste and O&M costs.
- Converted exterior lighting to LED at Bishop's Falls and Post Saunders offices;
- Variable frequency drives (VFDs) were installed on Unit 2 forced-draft (FD) fan motors at Holyrood Thermal Generating Station (the FD fans supply combustion air to the steam boilers);

In addition, as previously reported, Hydro continues with its ongoing control measures which also contribute to controlling the rural deficit, as follows:

- Continuing to capture waste heat in several of Hydro's diesel plants to heat Hydro premises;
- Planning diesel units' replacement sizes to optimize fuel efficiency;
- Monitoring diesel system fuel efficiency to identify poor performers so that corrective action may be taken;
- Utilizing commercial air flights during regular work hours where practical, rather than more expensive helicopter use;
- Having operators choose the most fuel efficient mix of engines, where possible, to supply the community load. This is done automatically in some plants;
- More effective planning and scheduling, which includes a significant coordination effort in the upfront planning process to ensure that delays and duplicate asset outages are minimized. Planning and scheduling results in better utilization of the workforce with the planner ensuring the available weekly capacity of each crew is matched to the estimated weekly work. Overall, planning and scheduling helps Hydro perform effective maintenance activities in the most efficient manner;
- Completing a life cycle cost analysis to help ensure the overall least-cost option is chosen when analyzing tenders for the purchase of new diesel engines. This process was used when new engines were put in service in Little Bay Islands, McCallum and Francois in 2011. In the life cycle cost analysis included items such as capital cost, overhaul cost, fuel cost (based upon fuel efficiency data), routine operation, and maintenance cost were considered;
- In 2008, Hydro moved the printing of customer bills to in-house resulting in savings versus an outside printing service company;
- In 2009, mailing costs were reduced by improved sorting of customer bills to avoid multiple mail outs to single customers with multiple accounts and by eliminating return envelopes for customers not paying by mail; and

- Hydro began offering e-billing to its customers in 2010. E-billing is an electronic paperless form of sending customer bills by email. This method of billing is convenient, beneficial to the environment and offers a cost savings on postage, paper and envelopes. As of December 31, 2015 there were 5,092 customers using e-bills as their method of billing. Based on a cost of approximately $0.83 to mail a customer bill, the savings from e-bills are $4,226 per month, or $50,700 annually.

3.2 Conservation and Demand Management (CDM) Program Initiatives

The high cost of generation in isolated diesel communities and growing system load in the L'Anse au Loup system provides opportunity for Hydro to implement energy efficiency programs specific to these areas. In 2012, two programs were launched to offer incentives and technologies for residential and commercial customers located in Hydro's isolated diesel communities. These programs continued in 2015 and further details are provided below.

<u>Isolated System Community Energy Efficiency Program</u>

The objective of this program is to provide outreach, education, and energy efficient products to residential and business customers in the remote diesel-system communities within Newfoundland and Labrador, free of charge. From 2012 to 2015 the program operated in 42 remote communities, installed 70,640 energy efficient products and helped customers save a total of 5.5 GWh of electricity. Overall, the program was successful and has increased local knowledge on energy efficiency and provided employment for over 48 local residents.

The program included residential and commercial direct installations with a focus on building knowledge and capacity in the communities by hiring and training local representatives. The representatives worked within their own communities to promote the program, provide useful information on energy use, and provide direct installation of energy efficient products, including low-flow showerheads and aerators, LED lamps, compact fluorescent lamps (CFLs), smart power strips, as well as hot water tank and pipe insulation.

In addition to offering direct installs, the program included retail rebates on energy efficient products while working with local retailers to offer a greater selection of energy efficient products, such as household appliances and electronics. Mini-campaigns targeting specific community needs were also integrated into the program, including a holiday LED light string exchange, a drain water heat-recovery project, a home energy audit and draft proofing pilot, and an energy efficient products consumer survey to assess the potential for developing an online retail store to offer reasonably priced small energy efficient technology products to customers in isolated communities.

2015 Program Highlights

- Direct installations of 22,469 products for 965 residential and business customers consisting of water saving technologies and specialty bulbs for specific lighting needs including chandelier, vanity, and flood lights. Energy savings for the 2015 direct installs totaled 1,426 MWh;
- During the direct installations, information was also collected about the type of lighting, heating, and appliances in the homes and businesses which will be used for future program development.

Isolated Systems Business Efficiency Program

The Isolated Systems Business Efficiency Program was launched in 2012. This program provides rebates and technical assistance for commercial customers in isolated diesel communities on coastal Newfoundland and Labrador. Hydro's energy efficiency team work one-on-one with customers to create a plan to address their energy efficiency needs, and provide ongoing technical support for projects undertaken. This custom approach has encouraged customers to undertake projects to improve the energy efficiency of lighting, refrigeration, motor controls, and other building systems. Customer incentives are based on energy savings and to the end of 2015, more than 60 audits have been completed. This program deals primarily with small business customers and since 2012 it has produced 207 MWh of annual energy savings.

4 Capital Initiatives

Automated Meter Reading Project

The ongoing implementation of Automated Meter Reading (AMR) will reduce meter reading costs inherent in the rural deficit over the long term through reduced salary expense.

Two AMR Collectors will become operational during 2016, one in Main Brook (MBK) and the other in Roddickton (RWC). These AMRs will service the communities of Main Brook, Croque, St. Juliens. Englee, Roddickton, Bide Arm and Conche.

LED Street Light Replacement Project

During 2015, Hydro pursued a pilot LED street light replacement project for the Town of Nain. A total of 125 high pressure sodium (HPS) street light fixtures were replaced with LED fixtures. Given the location and climate of Nain, this area will help provide for a full evaluation of the performance of LED street lights on an isolated system with challenging weather conditions.

The street light retrofit in Nain is expected to yield fuel cost savings due to lower energy requirements compared to high pressure sodium (HPS) lights. Hydro estimates approximate savings of 45,000 kWh, or $10,000 in diesel fuel costs annually. LED streetlights may also result in lower operating and maintenance costs than the existing HPS lights due to the elimination of re-lamping and longer life. Hydro will continue to evaluate further implementation of LED street lighting in other communities.

Appendix G
2016 Rural Deficit Report

Rural Deficit Annual Report

Summary of Specific Initiatives

August 3, 2017

A Report to the Board of Commissioners of Public Utilities

(pursuant to Order Nos. P.U. 14(2004) and P.U. 49(2016))

newfoundland labrador hydro
a nalcor energy company

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1.0 Introduction

Newfoundland and Labrador Hydro (Hydro) serves approximately 38,600 Rural Customers. Electrical service is provided to the majority of these customers at an operating loss or deficit, except for the approximately 11,200 Rural Customers served on the Labrador Interconnected System who pay rates which both recover costs as well as contribute to funding a portion of the rural deficit.

While there is no cost of service available by each diesel area or community, revenues from Rural Customers, particularly diesel areas, do not fully offset fixed costs. Therefore, the incremental cost of fuel has a direct impact to the rural deficit as it is not fully recovered from revenues from sales.

Hydro’s mandate to provide least-cost, safe, and reliable power to all its customers remains its primary focus. This report provides an overview of Hydro’s rural deficit, as well as the operating and capital initiatives undertaken by Hydro to manage costs and mitigate the rural deficit.

2.0 Rural Deficit Overview

Table 1

Hydro Rural Deficit($ Millions)[1]

$000,000	Annual Amounts					Year over Year			
	2012	2013	2014	2015	2016	2013/ 2012	2014/ 2013	2015/ 2014	2016/ 2015
Revenues	60.8	62.5	62.6	63.7	59.8	1.7	0.1	1.1	(3.9)
Costs:									
Operating Expenses	43.0	44.4	47.4	52.3	43.8	1.4	3.0	4.9	(8.5)
Fuel	27.6	28.9	35.7	26.8	26.8	1.2	6.8	(8.9)	0.0
Purchased Power	7.5	7.7	7.9	7.3	7.3	0.2	0.2	(0.6)	0.0
Depreciation	11.6	12.5	12.7	14.2	14.2	0.9	0.2	1.5	0.0
Return[2]	20.4	19.7	23.0	24.8	25.1	(0.7)	3.3	1.8	0.3
Total	110.1	113.2	126.7	125.4	117.2	3.0	13.5	(1.3)	(8.2)
Rural Deficit	**49.3**	**50.7**	**64.1**	**61.7**	**57.4**	**1.3**	**13.5**	**(2.4)**	**(4.3)**

Table 1 shows the rural deficit for 2012 to 2016, excluding customers on the Labrador Interconnected System. The 2014 Rural Deficit is estimated based on the 2014 actual costs combined with a portion of the $45.9 million deferred 2014 revenue deficiency allocated to the rural deficit. Rural deficits for 2015 and 2016 have been estimated based on the 2015 and 2016 Cost of Service studies for revenue deficiency, as filed in Hydro's May 18, 2017 Compliance Rates Application, updated to reflect actual 2015 and 2016 revenues and operating expenses.

[1] Excluding Labrador Interconnected System.
[2] Reflects return on debt only, for 2012 – 2013 inclusive.

The overall rural deficit of $57.4 million in 2016 represents a decrease of approximately $4.3 million, or 7.0%, over that of 2015. This is due to a decrease in operating expenses, partially offset by a decrease in revenues in 2016.

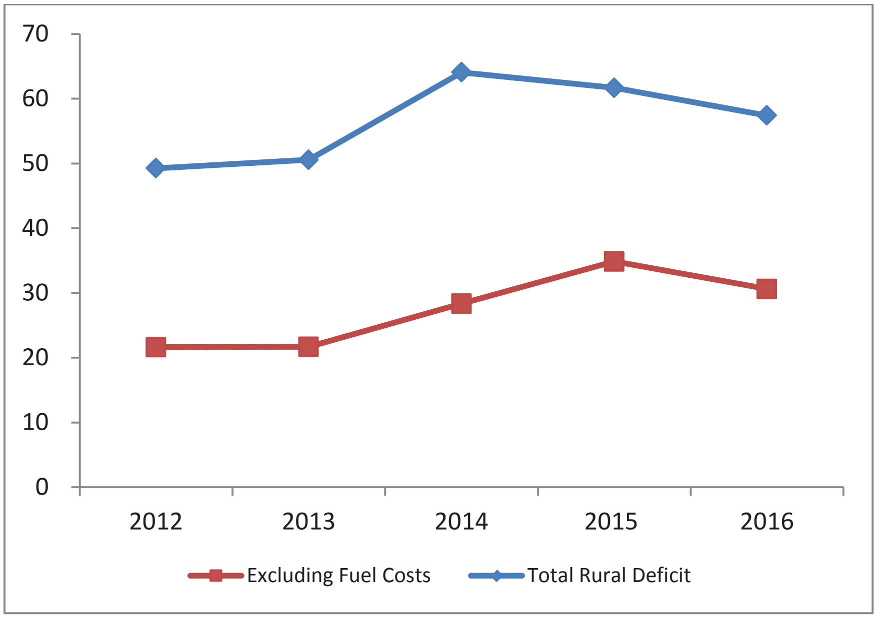

Chart 1
Five-Year Rural Deficit ($ millions)

Chart 1 shows that the rural deficit was relatively consistent between 2012 and 2013 when the impact of fuel costs is excluded. For 2014, the increased cost, excluding fuel, reflects the inclusion of 8.8% return on equity on rural assets.

3.0 Operating Initiatives

3.1 Internal Energy Efficiency Initiatives

Starting in 2008, Hydro focused on improving internal efficiency to reduce the internal use of energy. This program, which continued in 2016, targets reduction in energy usage in all facilities including diesel plants, offices, and line depots within the areas affecting the rural deficit. Throughout the year, Hydro completed or launched operating initiatives that are part of multi-year projects through its internal energy efficiency program. Such initiatives contribute to overall cost containment, a portion of which is allocated to Rural Customers and therefore contributes to deficit reduction. Initiatives completed in 2016 include:

- Installation of energy efficient lighting at the St. Brendan's, L'Anse-Au-Loup, and Postville diesel plants;
- Replacement of existing high bay lighting with energy efficient LED fixtures in the Bishop's Falls service building carpenter shop;
- Continuing to replace inefficient interior and exterior fixtures with more efficient LED fixtures at Bay d'Espoir, along with installing more efficient controls for heaters;
- Redesign of the compressed air system at the Bay d'Espoir plant and installation of a new, efficient compressor to reduce energy waste and operating and maintenance costs.
- Installation of energy efficient high bay lighting and exterior wall packs at the Wabush line depot; and
- Installation of variable frequency drives on Unit 2 forced-draft (FD) fan motors at the Holyrood Thermal Generating Station (the FD fans supply combustion air to the steam boilers).

In addition, Hydro continues with its ongoing control measures, which also contribute to controlling the rural deficit, as follows:

- Continuing to capture waste heat in several of Hydro's diesel plants to heat Hydro premises;
- Planning diesel units' replacement sizes to optimize fuel efficiency;
- Monitoring diesel system fuel efficiency to identify poor performers so that corrective action may be taken;
- Utilizing commercial air flights during regular work hours where practical, rather than more expensive helicopter use; and

- Having operators choose the most fuel efficient mix of engines, where possible,[3] to supply the community load.

Hydro has also focused on effective planning and scheduling, including a significant coordination effort in the upfront planning process to ensure that delays and duplicate asset outages are minimized. Planning and scheduling results in better utilization of the workforce with the planner ensuring the available weekly capacity of each crew is matched to the estimated weekly work. Overall, planning and scheduling help Hydro to perform effective maintenance activities in the most efficient manner.

Hydro continues to perform life cycle cost analysis to help ensure the overall least-cost option is chosen when analyzing tenders for the purchase of new diesel engines. This process was used when new engines were put in service in Little Bay Islands, McCallum, and Francois in 2011. The life cycle cost analysis included items such as capital cost, overhaul cost, fuel cost (based upon fuel efficiency data), routine operation, and maintenance costs.

Since 2008, Hydro has also reduced operating and maintenance costs in the area of customer billing. In 2008, Hydro transitioned from having customer bills printed by an outside printing service to completing the work internally. Further, in 2009, mailing costs were reduced by improved sorting of customer bills to avoid multiple mail outs to single customers with multiple accounts and by eliminating return envelopes for customers not paying by mail. In order to make billing more cost efficient and environmentally friendly, Hydro began offering e-billing to its customers in 2010. E-billing is an electronic paperless form of sending customer bills by email. This method of billing is convenient, beneficial to the environment, and offers a cost savings on postage, paper, and envelopes. As of December 31, 2016, there were 6,748 customers using e-bills as their method of billing.

[3] This is done automatically in some plants.

3.2 Conservation and Demand Management Program Initiatives

The high cost of generation in isolated diesel communities and growing system load in the L'Anse au Loup system provides an opportunity for Hydro to implement energy efficiency programs specific to these areas. In 2012, two programs were launched to offer incentives and technologies for residential and commercial customers located in Hydro's isolated diesel communities. These programs continued in 2016 and are further detailed below.

3.2.1 Isolated System Community Energy Efficiency Program

The objective of this program is to provide outreach, education, and energy efficient products to residential and business customers in the remote diesel-system communities within Newfoundland and Labrador, free of charge. From 2012 to 2016, the program operated in 42 remote communities, installed 76,000 energy efficient products, and helped customers save a total of 6.1 GWh of energy. Overall, the program was successful and has increased local knowledge on energy efficiency and provided employment for over 48 local residents.

The program included residential and commercial direct installations with a focus on building knowledge and capacity in the communities by hiring and training local representatives. The representatives worked within their own communities to promote the program, provide useful information on energy use, and provide direct installation of energy efficient products, including low-flow showerheads and aerators, LED lamps, compact fluorescent lamps, smart power strips, as well as hot water tank and pipe insulation.

In addition to offering direct installs, the program included retail rebates on energy efficient products while working with local retailers to offer a greater selection of energy efficient products, such as household appliances and electronics. Mini-campaigns targeting specific community needs were also integrated into the program, including a holiday LED light string exchange, a drain water heat-recovery project, a home energy audit and draft proofing pilot, and an energy efficient products consumer survey to assess the potential for developing an online retail store to offer reasonably priced small energy efficient technology products to customers in isolated communities.

3.2.2 2016 Program Highlights

- Direct installations of more than 5,700 products for 345 residential and business customers, consisting of water saving technologies and specialty bulbs for specific lighting needs including chandelier, vanity, and flood lights. Energy savings for the 2016 direct installs totaled 365 MWh; and
- During the direct installations, information was also collected about the type of lighting, heating, and appliances in the homes and businesses which will be used for future program development.

3.2.3 Isolated Systems Business Efficiency Program

The Isolated Systems Business Efficiency Program was launched in 2012. This program provides rebates and technical assistance for commercial customers in isolated diesel communities on coastal Newfoundland and Labrador. Hydro's energy efficiency team works one-on-one with customers to create a plan to address their energy efficiency needs, and provides ongoing technical support for projects undertaken. This custom approach has encouraged customers to undertake projects to improve the energy efficiency of lighting, refrigeration, motor controls, and other building systems. Customer incentives are based on energy savings and to the end of 2016, more than 65 audits have been completed. This program deals primarily with small business customers and since 2012 has produced 448 MWh of annual energy savings.

4.0 Capital Initiatives

4.1 Automated Meter Reading Project

The ongoing implementation of Automated Meter Reading (AMR) will reduce meter reading costs inherent in the rural deficit over the long term through reduced salary expense.

Two AMR Collectors became operational during 2016, one in Main Brook and the other in Roddickton. These AMRs service the communities of Main Brook, Croque, St. Juliens, Englee, Roddickton, Bide Arm, and Conche.

4.2 LED Street Light Replacement Project

During 2015, Hydro pursued a pilot LED street light replacement project for the Town of Nain. A total of 125 high pressure sodium (HPS) street light fixtures were replaced with LED street light fixtures. Given the location and climate of Nain, this area will help provide for a full evaluation of the performance of LED street lights in an isolated system with challenging weather conditions.

The street light retrofit in Nain will yield savings of approximately 45,000 kWh of electricity a year, which offsets approximately 12,000 litres of fuel consumption at the diesel plant. LEF streetlights may also contribute to lower operating and maintenance costs than HPS street lights due to the elimination of re-lamping requirements, and longer life. Hydro continues to evaluate the Nain project and anticipates expanding the use of LED street lights across its rural diesel systems in the near future.

5.0 Conclusion

In 2016, Hydro continued its efforts to mitigate the rural deficit by reducing operating and capital costs. Hydro’s efforts include cost-reduction initiatives as well as energy conservation initiatives, as described in this report. Hydro remains committed to reducing the rural deficit and will continue to pursue opportunities to reduce costs and increase energy conservation.

Appendix H
2017 Rural Deficit Report

Rural Deficit Annual Report

Summary of Specific Initiatives

March 29, 2018

A Report to the Board of Commissioners of Public Utilities

(pursuant to Order Nos. P.U. 14(2004) and P.U. 49(2016))

newfoundland labrador hydro
a nalcor energy company

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1.0 Introduction

Newfoundland and Labrador Hydro (Hydro) serves approximately 38,600 Rural Customers. With the exception of approximately 11,200 Rural Customers served on the Labrador Interconnected System, whose rates recover costs and contribute to funding a portion of the rural deficit, electrical service is provided to these customers at an operating loss (deficit).

While there is no cost of service available by each diesel area or community, revenues from Rural Customers, particularly diesel areas, do not fully offset fixed costs. Therefore, the incremental cost of fuel has a direct impact on the rural deficit as it is not fully recovered from sales revenues.

Hydro's mandate to provide safe, reliable, and least-cost power to all its customers remains its primary focus. This report provides an overview of Hydro's rural deficit, as well as the operating and capital initiatives undertaken by Hydro to manage costs and mitigate the rural deficit.

2.0 Rural Deficit Overview

Table 1 provides rural deficit estimates for 2013 to 2017, excluding customers on the Labrador Interconnected System. The rural deficit estimates for 2013 to 2016 reflect test year projected costs. The rural deficit estimate for 2017 is calculated based on a pro forma 2017 Cost of Service.

Table 1

Hydro Rural Deficit Estimates ($ millions)

	Annual Amounts					Year over Year			
	2013	**2014**	**2015**	**2016**	**2017**	**2014/ 2013**	**2015/ 2014**	**2016/ 2015**	**2017/20 16**
Revenues (A)	62.5	62.6	63.7	59.8	58.6	0.1	1.1	(3.9)	(1.2)
Costs[1]									
Operating Expenses	44.4	47.4	52.3	43.8	43.6	3.0	4.9	(8.5)	(0.2)
Fuel	28.9	35.7	26.8	26.8	27.8	6.8	(8.9)	0.0	1.0
Purchased Power	7.7	7.9	7.3	7.3	7.2	0.2	(0.6)	0.0	(0.1)
Depreciation	12.5	12.7	14.2	14.2	17.3	0.2	1.5	0.0	3.1
Return[2]	19.7	23.0	24.8	25.1	23.1	3.3	1.8	0.3	(1.8)
Total Costs (B)	113.2	126.7	125.4	117.2	119.0	13.5	(1.3)	(8.2)	1.5
Rural Deficit (A-B)	**50.7**	**64.1**	**61.7**	**57.4**	**60.4**	**13.5**	**(2.4)**	**(4.3)**	**3.0**

The $60.4 million rural deficit in 2017 represents an increase of approximately $3.0 million, or 5.2%, over that of 2016. The increase is primarily related to:

- Decreased revenues – primarily related to the July 1, 2016 Rate Stabilization Plan rate change, which reduced Hydro's rural revenue during the first half of 2017;[3] and

[1] Table 1 does not include the costs incurred for CDM programs offered in rural communities as they are captured in Hydro's CDM Deferral Account, approved in P.U. 49(2016).
[2] 2013 reflects return on debt only.
[3] More of Hydro's sales occur in the first half of the year than the second half; therefore, the July 1, 2016 RSP Rate change impacted Hydro's 2017 revenues more than 2016 revenues.

- Increased depreciation costs relative to the 2015 Test Year - related to capital investments on isolated systems[4] and the allocation of capital investments on the Island Interconnected system to Hydro Rural (including TL267).[5]

Increases were partially offset by lower return. Return was lower in 2017 than 2016 due to the inclusion of more capital in rate base during 2017 than the 2015 Test Year previous year without corresponding increases in revenues.

Chart 1 compares the total rural deficit with the rural deficit excluding fuel costs. Fuel costs are consistently one of the primary cost drivers in rural deficit areas. As fuel prices are volatile and vary considerably from year to year, it is appropriate to isolate fuel costs when considering the management of the rural deficit.

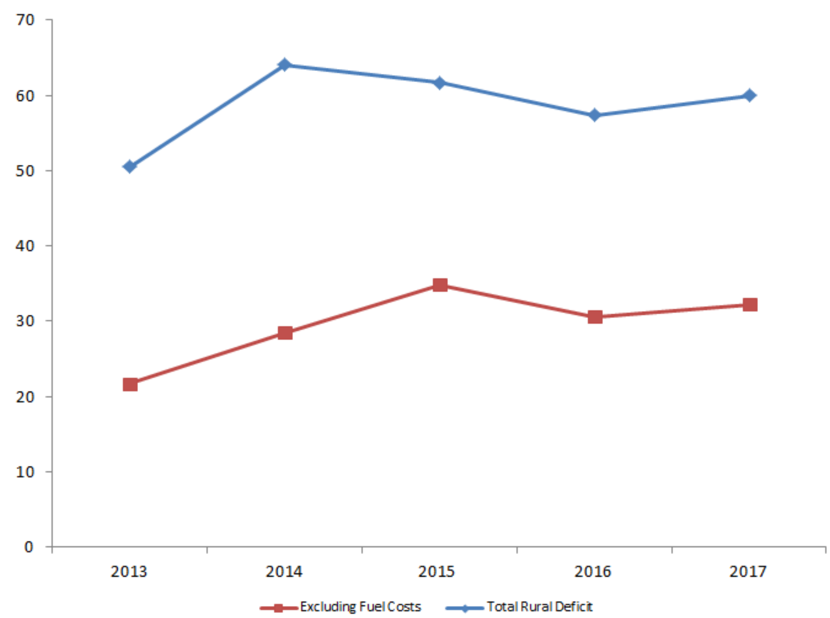


Chart 1
Five-Year Rural Deficit ($ millions)

[4] Hydro's response to NP-NLH-191 details the primary capital investments in its rural isolated systems for 2017, 2018, and 2019. The response can be accessed at: http://pub.nf.ca/applications/NLH2017GRA/rfi/NP-NLH-191.PDF.

[5] TL267 is a 230 kV transmission line from Bay d'Espoir to Western Avalon. The line was commissioned in 2017 and is reflected in 2017 rate base for half the year. Capital costs and associated depreciation are allocated to rural based on coincident peak demand.

3.0 Operating Initiatives

3.1 Internal Energy Efficiency Initiatives

Starting in 2008, Hydro focused on improving internal efficiency. This program, which continued in 2017, targets reduction in energy usage in all facilities including diesel plants, offices, and line depots within the areas affecting the rural deficit. Since it began in 2008, the program has provided cumulative energy savings of 17,031 MWh.

Throughout the year, Hydro completed or launched operating initiatives that are part of multi-year projects through its internal energy efficiency program. Such initiatives contribute to overall cost containment, a portion of which is allocated to Rural Customers and therefore contributes to deficit reduction. Initiatives completed in 2017 include:

- Installation of energy efficient lighting at the St. Anthony, Mary's Harbour, and Port Hope Simpson diesel plants, resulting in savings of 80 MWh, 17 MWh, and 18 MWh, respectively;
- Installation of energy efficient lighting and occupancy sensor control in the Bishop's Falls warehouse, along with efficiency upgrades to HVAC and lighting in the Services Building, resulting in energy savings of 76 MWh;
- Installation of variable frequency drives on the largest motors at Grey River diesel plant, resulting in energy savings of 63 MWh;
- Continuing to replace inefficient interior and exterior fixtures with more efficient LED fixtures at Bay d'Espoir, along with installing more efficient controls for heaters, resulting in savings of 38 MWh.

In addition, Hydro has continued the following in an effort to manage the rural deficit:

- Capturing waste heat in several of Hydro's diesel plants to heat Hydro premises;
- Planning diesel units' replacement sizes to optimize fuel efficiency;
- Monitoring diesel system fuel efficiency to identify poor performers so that corrective action may be taken;

- Utilizing commercial air flights during regular work hours where practical, rather than more expensive helicopter use;
- Choosing the most fuel efficient mix of engines, where possible,[6] to supply the community load;
- Finalizing a commercial agreement to return the Mary's Harbour mini hydro facility to service;
- Having running maintenance (i.e. oil changes) completed by diesel system representatives rather than travel maintenance crews to remote communities; and
- Participating in the Canadian Off Grid Utilities Association to work with other Canadian utilities with remote diesel plants for comparison of operating procedures and new technology to enhance operations and maintenance.

Hydro has also focused on effective planning and scheduling, including a significant coordination effort in the upfront planning process to ensure that delays and duplicate asset outages are minimized. Planning and scheduling results in better utilization of the workforce where the planner ensures the available weekly capacity of each crew is matched to the estimated weekly work. Overall, planning and scheduling supports performing maintenance activities in the most efficient manner.

Hydro continues to perform life-cycle cost analysis to help ensure the overall least-cost option is chosen when analyzing tenders for the purchase of new diesel engines. The life-cycle cost analysis includes items such as capital, overhaul, and fuel (based upon fuel efficiency data), and routine operation and maintenance costs.

Since 2008, Hydro also reduced operating and maintenance costs in the area of customer billing by transitioning from outsourcing the printing of customer bills to completing this work internally and implementing efficiency measures to reduce duplication and mailing costs. Further to this, in 2010, Hydro introduced e-billing to its customers to further reduce

[6] This is done automatically in some plants.

costs and encourage environmental efficiency. As of December 31, 2017, 8,962 of Hydro's customers use e-bills as their method of billing, compared to 6,748 in 2016, an increase of 33%.

3.2 Conservation and Demand Management Program Initiatives

The high cost of generation in isolated diesel communities and growing system load in the L'Anse au Loup system provides an opportunity for Hydro to implement energy efficiency programs specific to these areas. In 2012, two programs were launched to offer incentives and technologies for residential and commercial customers located in Hydro's isolated diesel communities. These programs continued in 2017 and are further detailed below.

3.2.1 Isolated System Community Energy Efficiency Program

The Isolated Systems Community Energy Efficiency Program is a program specifically targeted to residential and commercial customers in Hydro's Isolated Diesel systems. The objective of the program is to provide outreach, education, and energy efficient products free of charge to residential and business customers in the remote diesel system communities within Newfoundland and Labrador. From 2012 to 2017, the program operated in 42 remote communities and installed 94,250 energy efficient products. The program achieved over 1.1 GWh in energy savings in 2017 and a cumulative 7.2 GWh of energy savings since its inception. Overall, the program has been successful in achieving energy savings and educating customers on the benefits and importance of energy efficiency. Further, it has provided employment for over 55 local residents.

The Isolated Systems Community Energy Efficiency Program includes residential and commercial direct installations and focuses on building knowledge and capacity in the communities by hiring and training local representatives. These representatives work within their own communities to promote the program, provide useful information on energy use, and provide direct installation of energy efficient products, including low flow showerheads, faucet aerators, LED lamps, specialty size light bulbs, smart power strips, and hot water tank and pipe insulation.

In addition to offering direct installations, the program has included retail rebates on energy efficient products while working with local retailers to expand their selections of energy efficient products, such as household appliances and electronics. Mini-campaigns targeting specific community needs have also been integrated into the program, including a holiday LED light string exchange, a drain water heat-recovery project, a home energy audit and draft proofing pilot. An energy efficient products consumer survey to assess the potential for developing an online retail store to offer reasonably priced small energy efficient technology products to customers in isolated communities has also been completed. In 2017, trained representatives also provided interactive school classroom presentations for children in kindergarten through grade six.

In 2017, 1,007 residential and business customers received direct installation of 17,275 products consisting of water saving technologies and LED specialty bulbs for lighting needs, achieving energy savings of 990 MWh. While this work was ongoing, information was collected about the type of lighting, heating, and appliances in the homes and businesses, which will be used for future program planning.

3.2.2 Isolated Systems Business Efficiency Program

The Isolated Systems Business Efficiency Program was launched in 2012. The program provides rebates and technical assistance for commercial customers in isolated diesel communities on coastal Newfoundland and Labrador. Hydro’s energy efficiency team works one-on-one with customers to create a plan to address their energy efficiency needs and provides ongoing technical support for projects undertaken. This custom approach has encouraged customers to undertake projects to improve the energy efficiency of lighting, refrigeration, motor controls, and other building systems. In 2017, 23 audits were completed in the L’Anse au Loup system providing information for future projects. This program deals primarily with small business customers and has achieved 472 MWh of annual energy savings since 2012.

3.2.3 Postville Direct Load Control Pilot

In 2017, Hydro initiated a pilot project to test whether a Direct Load Control (DLC) strategy could automatically and reliably maintain an isolated diesel system below a pre-set demand threshold without negatively impacting customers. The project also includes the economic evaluation of such an approach in relation to the alternative of increasing diesel plant capacity. The pilot project involves residential and commercial participants with the direct installation of domestic hot water tank controllers for residential customers and electric thermal storage (ETS) space heaters for commercial customers. All devices installed throughout the community communicate wirelessly with a control system in the diesel plant. If the DLC technology proves to be a reliable alternative, it has the potential to be implemented in other communities as a mechanism to defer select capital projects driven by load growth and to reduce outage recovery times due to cold load pick up. The DLC system was installed in 2017, and results are expected to be finalized by the third quarter of 2019.

4.0 Capital Initiatives

4.1 Energy Efficient Lighting in Diesel Plants

In Hydro's 2018 Capital Budget Application, a three-year project to install LED lighting fixtures in nine diesel plants located in Cartwright, Charlottetown, Francois, Grey River, Makkovik, McCallum, Nain, Norman Bay, and St. Lewis was proposed. A cost-benefit analysis of replacing the lighting versus the status quo determined that replacement of the lighting had positive net present value and would provide a total savings of $374,429.

4.2 LED Street Lights in Isolated Systems

In 2015, Hydro initiated a pilot LED street light replacement project for the Town of Nain. A total of 125 high pressure sodium (HPS) street light fixtures were replaced with LED street light fixtures. The street light retrofit yields savings of approximately 45 MWh annually, which offsets approximately 12,000 litres of fuel consumption. LED streetlights may also contribute to lower operating and maintenance costs than HPS street lights due to the elimination of re-lamping requirements, and longer life.

Following the pilot project, Hydro engaged an independent consultant to survey its customers in Nain to gauge their perception of the LED street lights. A copy of their report is attached as Appendix A. Most respondents noted that street lights were brighter, and identified night time visibility and overall safety as primary benefits of the change. The majority of respondents also indicated satisfaction with the LED lights' performance in challenging weather conditions.

Building on the success of the Nain pilot LED streetlight project and the positive customer feedback, Hydro intends to expand the use of LED streetlights into Cartwright in conjunction with the replacement of lighting in the diesel plant, as described in section 4.1.

5.0 Conclusion

During 2017, Hydro continued to pursue activities to manage the rural deficit, including cost-reduction and energy conservation initiatives, as described in this report. As a result of decreased revenues and increased capital investment, the rural deficit increased $3.0 million in 2017 to $60.4 million. Hydro remains committed to reducing the rural deficit and will continue to pursue opportunities to reduce costs and increase energy conservation going forward.

Take Charge Isolated Systems: Nain LED Streetlight Survey

November 27th, 2017

Summerhill
1329 Barrington Street, Halifax, NS B3J 1Y9

Contact:
Jon Hudson, Director, Atlantic Canada
jhudson@summerhill.com
(902) 420-0709

Background

Newfoundland and Labrador Hydro (NL Hydro) Hydro completed an LED street light replacement project in 2015 for the Town of Nain. In total there were 125 high pressure sodium (HPS) street lights replaced with LED fixtures. The climate in Nain presents the opportunity to evaluate the performance of these fixtures under challenging weather conditions.

The retrofit of these fixtures was pursued based on the fact they would yield a fuel cost savings due to lower energy requirements compared to HPS lights. It was calculated that the savings would be approximately 45,000 kWh, or 12,000 litres of diesel fuel annually. Additional savings are possible in the areas of operating and maintenance costs (based on longer lifespans of the LED lamps).

Purpose

The purpose of this survey is to gauge local residents' perception of the LED streetlights. Emphasis was placed on collecting feedback from members of the Town Council. Results from the survey will inform NL Hydro when evaluating similar projects in other isolated communities.

Process

Summerhill designed a short survey for local residents based on information requested by NL Hydro. This survey was administered to participants by two local representatives. The initial participation target for the survey was a minimum of 50 community members including five Town Council staff (10% of the sample). Surveys were conducted by in-person meetings or over-the-phone between April and June, 2017. Survey responses were entered online and reviewed and analyzed by Summerhill.

Note: For the qualitative questions (8 and 9), responses were categorized by key points or frequently used key words. Each key word was tallied the corresponding category. Some respondents noted several keywords in their response, each were accounted for in these sections.

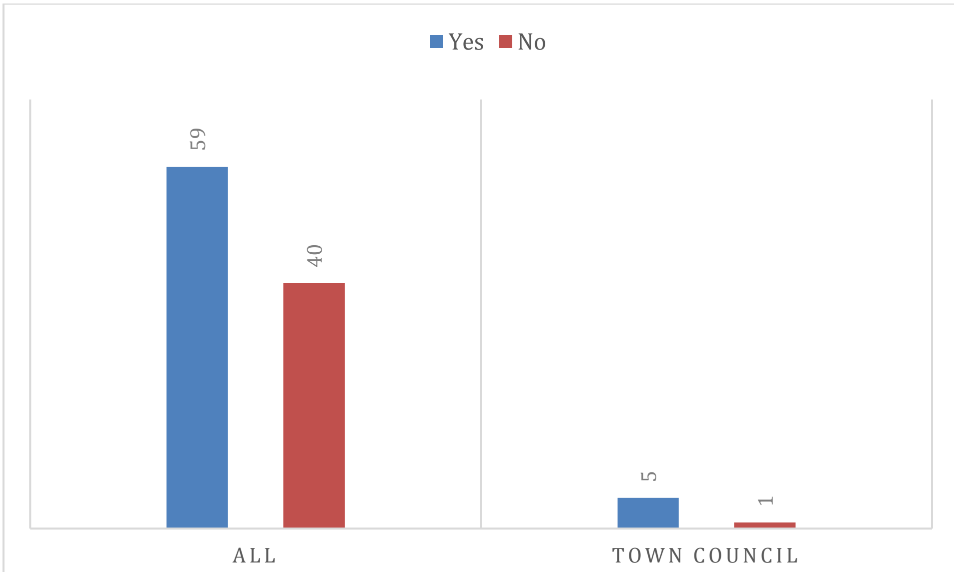
Participation

In order to encourage participation the survey included a prize draw for a $100 prepaid credit card. In total there were 99 participants. Based on the response to Question 2, there were 6 Town Council members who participated in the survey, leaving the remaining 93 as non-governmental townspeople.

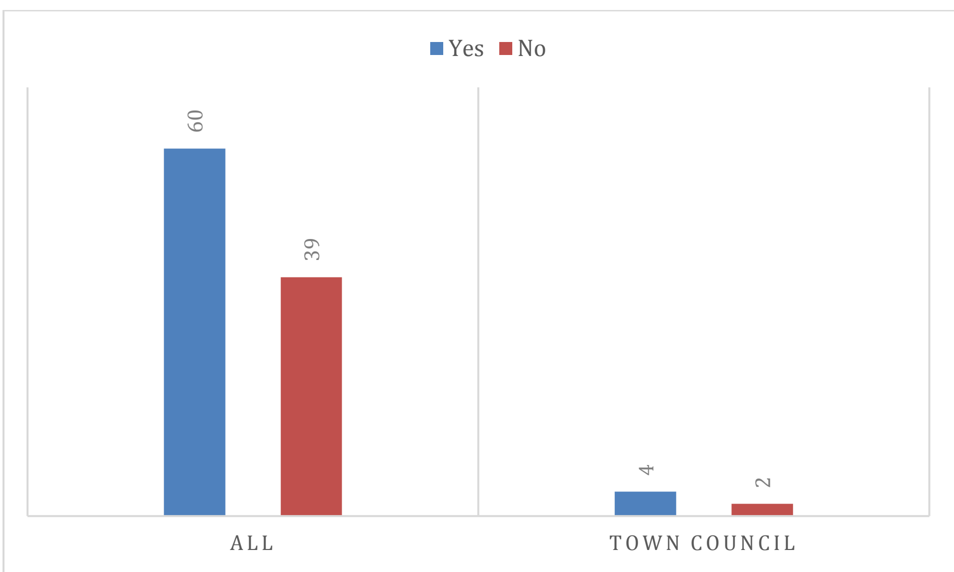
Awareness

Questions 3 and 4 assessed the community awareness of the streetlight change out.

Question 3 asked respondents if they recalled the construction on street lights in 2015. The results show that just under 60% of respondents remembered the events. Among Town Council members, one 1 respondent did not remember the construction (see results below).



Question 4 asked if the respondent was aware that the Nain street lights were converted to LED during the construction of 2015. A similar percentage of people as in Question 2 indicated that they were aware of this.



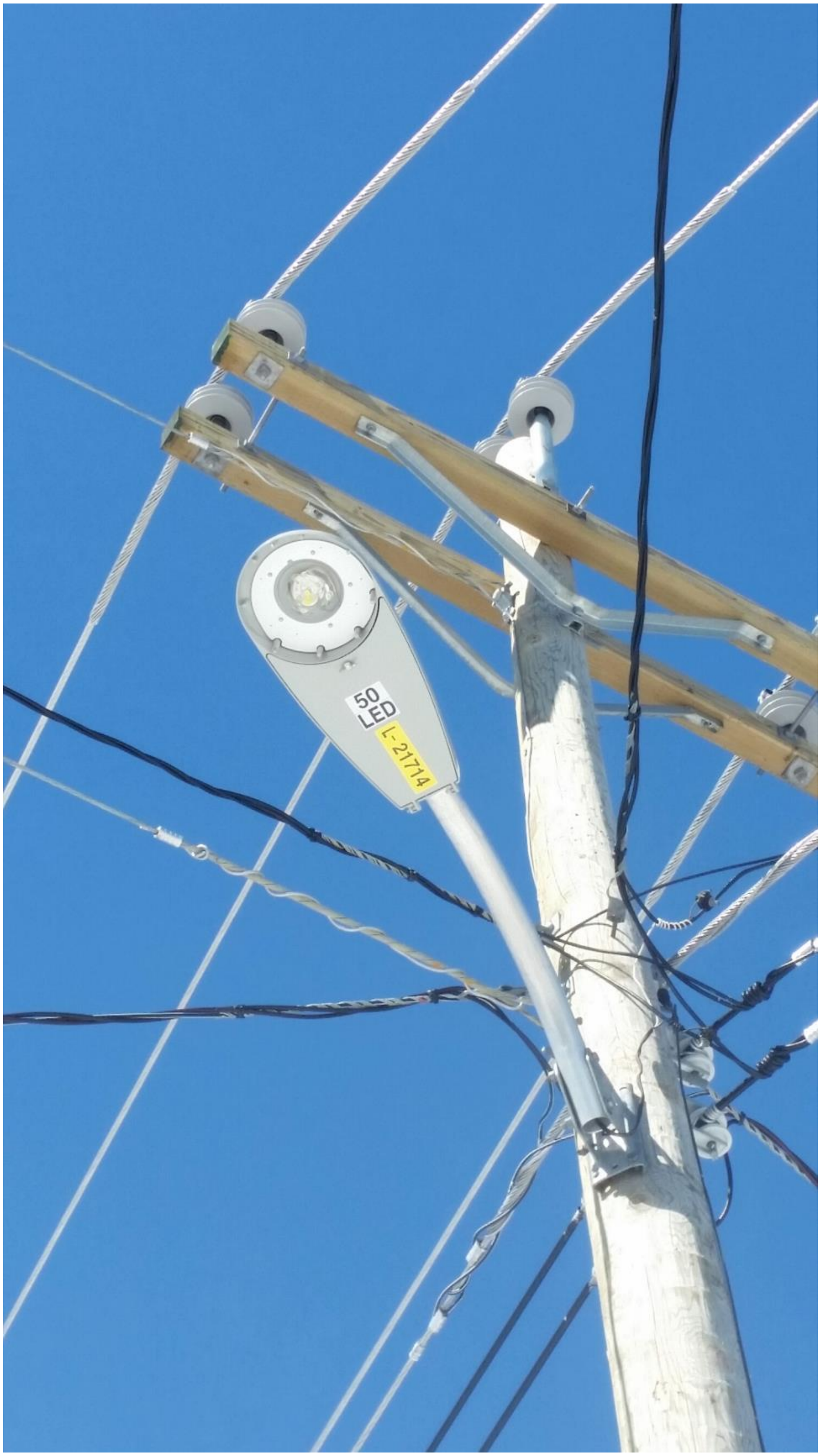
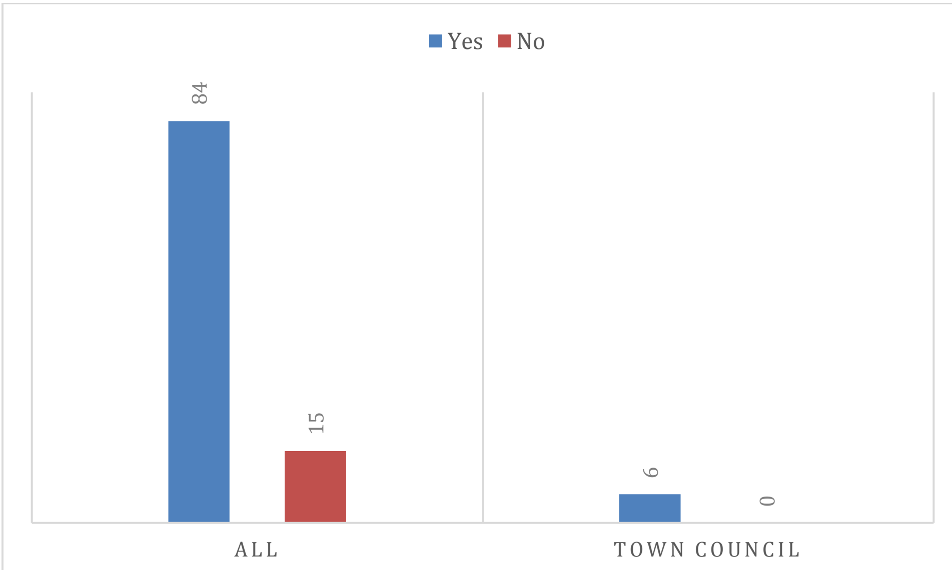


Photo above: New LED Streetlight

Feedback

Question 5 asked the respondent if they have noticed a difference in the new lights relative to the lights that were replaced. A very high percent of non-government respondents (more than 85%) and all of the Town Council members have noticed a difference in the lighting since the change out, as indicated by the below graph.



In Question 6, we asked those that responded with 'Yes" to Question 4 what the difference was that they noticed. Their responses were not restricted and the following table is a tally of all the 'hits' each topic/point received in the answer. The brightness appears to be a common answer for most respondents, this is complemented by greater visibility.

Noticed Difference	"Hits" (All)	"Hits" (Town Council)
Brighter	64	3
More Visibility	9	0
Different/odd colors	5	0
Further reach	5	0
More Dull/Darker	4	0
Feel Safe	3	0
Blow quicker	1	1
Less reach/smaller radius	1	1
Harder to sleep	1	0
LEDs	1	0
Longer lasting	1	0
More attractive	1	0
Harder to see	0	1
Total	96	6

Question 7, asked the participant to describe any benefits that may have arose from changing to the LED streetlight. Similar to Question 5, we created key word categories for the answers. It appears that nighttime visibility and overall safety are the two main benefits of the change that the general population and Town Council members remarked.

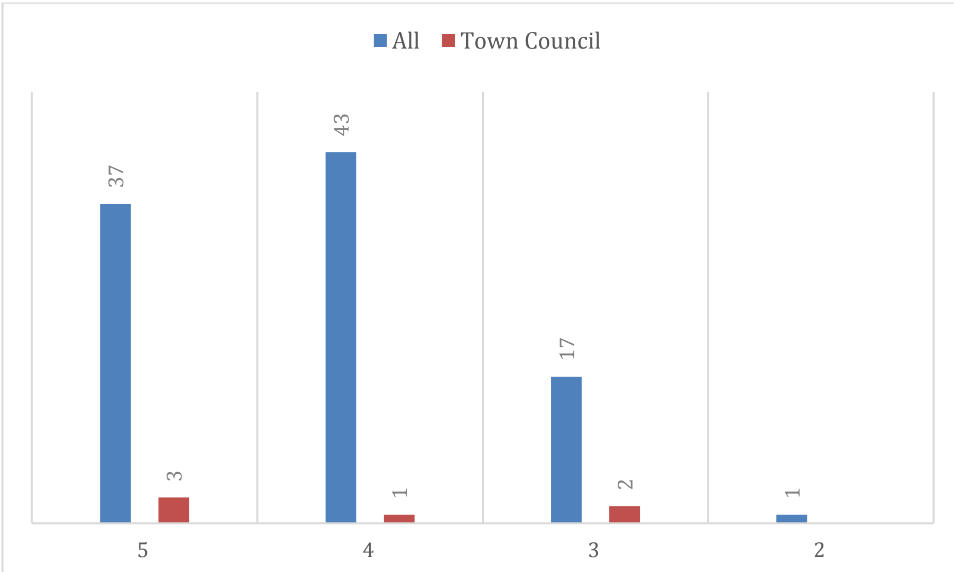
Benefit	"Hits" (All)	"Hits" (Town Council)
Visibility at night (brightness, wider range, and clarity)	33	4
Safety	28	2
Energy efficient	7	1
Longer lasting	6	1
None/didn't notice	4	0
Aesthetically Appealing	1	1
Total	79	9

Photo Above: More visibility on the streets at night

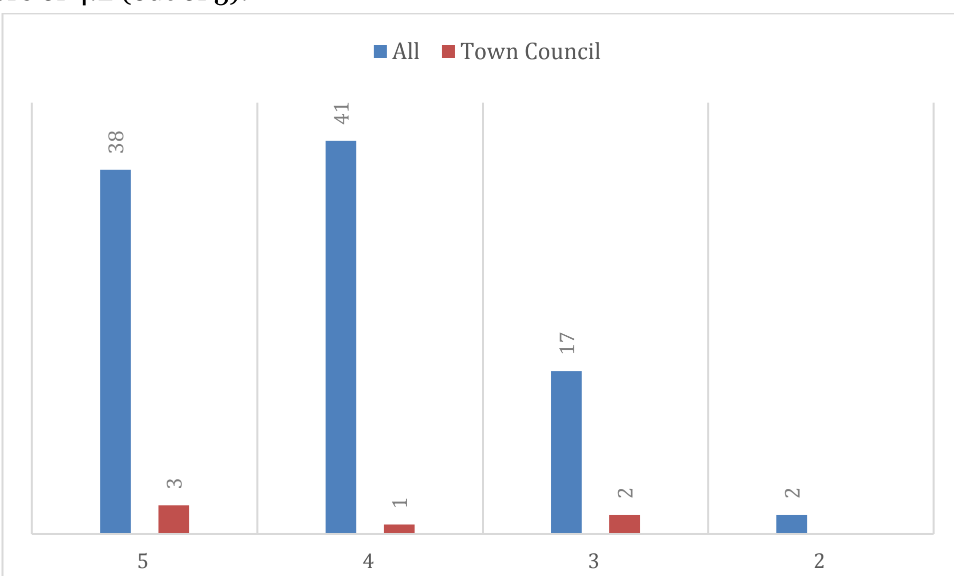
Weather Conditions

Question 8 was based on how the participant felt that the lights held up with various weather conditions.

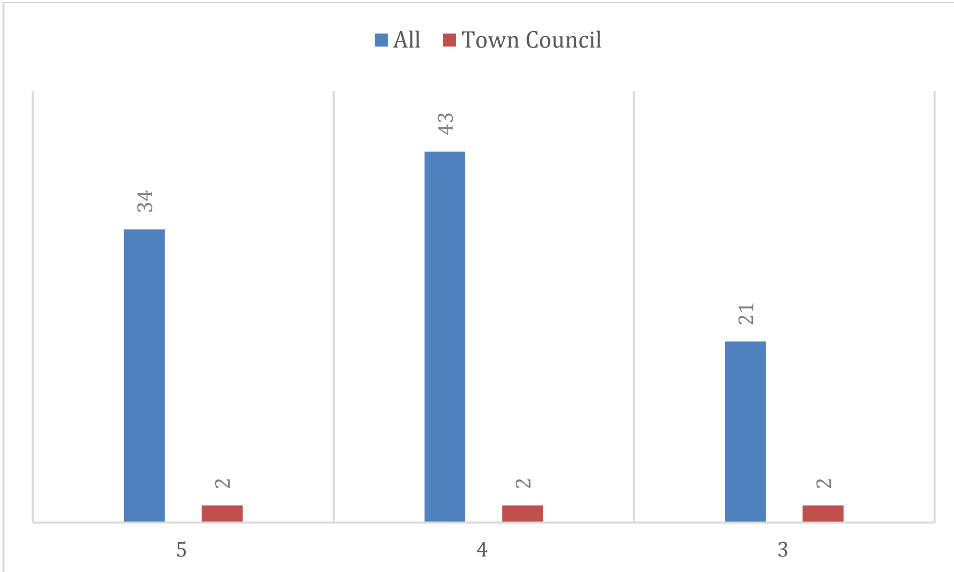
In high wind scenarios, the participants and Town Council members awarded the lights an average score of 4.2 (out of 5).



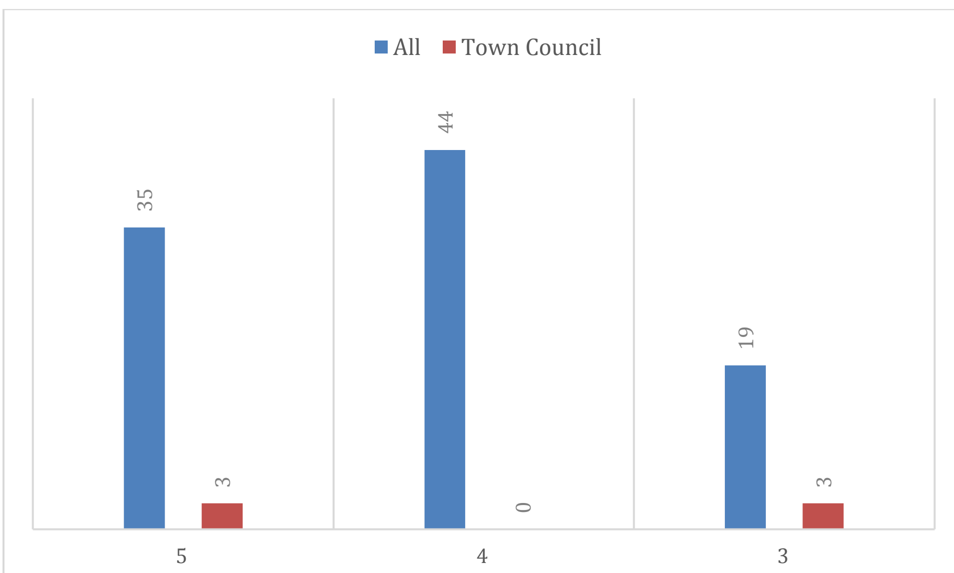
In extreme cold conditions, the participants and Town Council members awarded the lights an average score of 4.2 (out of 5).



In snowy conditions, the participants awarded the LED lights an average of 4.1 (out of 5) while the Town Council members awarded the lights an average score of 4 (out of 5).



In heavy rain conditions, the participants awarded the LED lights an average of 4.2 (out of 5) while the Town Council members awarded the lights an average score of 4 (out of 5).



Comments

Most of the comments were very positive. Many respondents requested that more streetlights be installed and commented about how they have helped improve safety from people and wildlife in the night time.

There were a few negative comments that included:

- The lights are too bright,
- Dissatisfaction with the cool color temperatures, and;
- difficulty sleeping. Due to the brightness of the lights.

One respondent in particular mentioned that they were not happy with having the LED streetlight on their property and would like to have it removed (see below). It can be assumed that this customer is upset with the placement of the pole as opposed to the technology that it uses.

Photo above: Home on Morhardt Road

There were two individuals who indicated that lights were not working. There are still some HPS street lights that remain in the community, the respondents did not specify in their response whether the faulty fixtures were the new LED or old HPS. The locations of faulty fixtures included:

- Harmony (light is flickering),
- Alakkatik (not working),
- Amaguk (not working), and;
- Commercial (not working).

For a more in depth look at the comments, please review the table below.

Comments
Harder to sleep
Want more street lights
I like them, we need more on my street
Thanks for considering bringing brighter lights for the community
Need LED lights put on all the street lights, uptown.

I don't remember where the busted lights are but be good if they were working at night anyway.
I just moved to Nain in January, 2017. I have not noticed any issues with the lights since I arrived.
There good to have, brighter, not so yellow colored.
Thanks for installing new LED lights in the community to make it more safe.
Need street lights over to the ball field
Need more street lights
No comment but would like to have the light street change same color it was.
I don't know if it is distance between lights or if some are not replaced but still seem to be very dark across in town.
Thanks for the conversion.
It is a lot better now, better than before.
Going to watch closer.
I never thought about paying attention to the street lights until now, thanks! Haha!
Need more street lights
A lot better than old lights.
Need more lights.
Need more
Cover broke on light near my house.
I find the LED lights do not last longer than the old bulbs.
Needs upgrade everywhere, lot brighter
Thanks.
I believe that there should be efforts made to ensure all parts of the community are lit at all times to ensure safety and well-being of community members.
Too bright in my room
Would be nice if they can get checked regularly. Scary out in the dark, especially bar girls (club girls) and women walking alone.
It would be good to have the old lights back.
Like anything new after awhile we get used to the usage.
Need a lot more lights.
I like these new lights
I would like a hydro pole removed from my yard
Needs extra street lights in some areas.

Appendix: Survey Questions

LED Street Light – Customer Survey

1. General Information

Customer Name	
Customer Phone Number	
Customer Address	

2. Are you a Town Hall Employee?

- ○ Yes
- ○ No

3. Do you recall the construction in 2014 on Nain's street lights?

- ○ Yes
- ○ No

4. Were you aware that Nain's street lights were converted to LED?

- ○ Yes
- ○ No

5. Have you noticed a difference in the new lights?

- ○ Yes
- ○ No

6. If so, then what?

____
____
____

7. Can you briefly describe any benefits you see to having the new lights?

____
____
____

8. Please Describe how the new LED lights perform in the extreme weather conditions

	1	2	3	4	5
High Wind	○	○	○	○	○
Extreme Cold	○	○	○	○	○
Snow	○	○	○	○	○
Heavy Rain	○	○	○	○	○

9. Please indicate all failed lights that you have noticed

Approximate address	Burned out/not working	Flickering
1.		
2.		
3.		
4.		

10. Please provide any additional comments.

____
____
____
____

Date: __________________________________
Customer Signature: _______________________
Rep Signature: ____________________________

Appendix I
2015 Energy Supply Deferral

Energy Supply Cost Variance Deferral Account
December 31, 2015

Line No.	Particulars	Holyrood Gas Turbine	Hardwoods Gas Turbine	Stephenville Gas Turbine	St. Anthony Diesel	Hawkes Bay Diesel		Total
1	2015 Actual Fuel Costs ($)	11,406,709	2,067,100	1,135,250	112,135	21,264		14,742,458
2	2015 Test Year Fuel Costs ($)	1,977,306	1,089,250	407,134	55,917	31,223		3,560,830
3	**A - Thermal Generation Cost Variance ($) [Line 1 - Line 2]**							**11,181,628**

Line No.	Particulars	Nalcor Exploits	Star Lake	Rattle Brook	CBPP Cogen	St. Lawrence Wind	Fermeuse Wind	Total
4	2015 Actual Power Purchases (kWh)	559,495,357	135,319,578	13,475,222	62,489,005	94,784,871	87,213,249	
5	2015 Test Year Power Purchases (kWh)	633,500,000	142,180,000	15,000,000	51,070,000	104,800,000	84,410,000	
6	2015 Test Year Cost ($/kWh)	0.04000	0.04000	0.08358	0.20132	0.06561	0.06937	
7	**B - Power Purchase Variance ($) [(Line 4 - Line 5) x Line 6)]**	**(2,960,186)**	**(274,417)**	**(127,441)**	**2,298,874**	**(657,093)**	**194,461**	**(1,525,802)**
8	**C - Holyrood TGS Fuel Costs/(Savings) ($) [(D/E)*F]**							**5,044,603**
9	**Energy Supply Cost Variance ($) [A+B+C]**							**14,700,429**
10	**Cost Variance Threshold ($)**							**500,000**
11	**Energy Supply Cost Variance Deferral ($)**							**14,200,429**
12	D - 2015 Test Year Holyrood Average Fuel Cost (bbl)							64.41
13	E - 2015 Test Year Fuel Conversion Factor (kWh/bbl)							618
14	F - Annual kWh variance - Actual vs. Test Year (kWh) (G1-G2)							48,401,874
15	G1 - 2015 Test Year Consumption (kWh)							1,042,340,000
16	G2 - 2015 Actual Consumption (kWh)							993,938,126

Appendix J
2016 Energy Supply Deferral

Energy Supply Cost Variance Deferral Account
December 31, 2016

Line No.	Particulars	Holyrood Gas Turbine	Hardwoods Gas Turbine	Stephenville Gas Turbine	St. Anthony Diesel	Hawkes Bay Diesel		Total
1	2016 Actual Fuel Costs ($)	23,323,034	3,386,069	1,675,010	139,206	97,318		28,620,637
2	2015 Test Year Fuel Costs ($)	1,977,306	1,089,250	407,134	55,917	31,223		3,560,830
3	**A - Thermal Generation Cost Variance ($) [Line 1 - Line 2]**							**25,059,807**

Line No.	Particulars	Nalcor Exploits	Star Lake	Rattle Brook	CBPP Cogen	St. Lawrence Wind	Fermeuse Wind	Total
4	2016 Actual Power Purchases (kWh)	495,379,594	135,727,322	15,164,860	70,566,373	103,054,642	86,981,831	
5	2015 Test Year Power Purchases (kWh)	633,500,000	142,180,000	15,000,000	51,070,000	104,800,000	84,410,000	
6	2015 Test Year Cost ($/kWh)	0.04000	0.04000	0.08358	0.20132	0.06561	0.06937	
7	**B - Power Purchase Variance ($) [(Line 4 - Line 5) x Line 6)]**	**(5,524,816)**	**(258,107)**	**13,779**	**3,925,010**	**(114,513)**	**178,408**	**(1,780,239)**
8	**C - Holyrood TGS Fuel Costs/(Savings) ($) [(D/E)*F]**							**1,683,428**
9	**Energy Supply Cost Variance ($) [A+B+C]**							**24,962,996**
10	**Cost Variance Threshold ($)**							**500,000**
11	**Energy Supply Cost Variance Deferral ($)**							**24,462,996**
12	D - 2015 Test Year Holyrood Average Fuel Cost (bbl)							64.41
13	E - 2015 Test Year Fuel Conversion Factor (kWh/bbl)							618
14	F - Annual kWh variance - Actual vs. Test Year (kWh) (G1-G2)							16,152,124
15	G1 - 2015 Test Year Consumption (kWh)							1,042,340,000
16	G2 - 2016 Actual Consumption (kWh)							1,026,187,876

Appendix K
2017 Energy Supply Deferral

Energy Supply Cost Variance Deferral Account
December 31, 2017

Line No.	Particulars	Holyrood Gas Turbine	Hardwoods Gas Turbine	Stephenville Gas Turbine	St. Anthony Diesel	Hawkes Bay Diesel		Total
1	2017 Actual Fuel Costs ($)	17,184,958	1,321,148	541,147	81,558	37,141		19,165,952
2	2015 Test Year Fuel Costs ($)	1,977,306	1,089,250	407,134	55,917	31,223		3,560,830
3	**A - Thermal Generation Cost Variance ($) [Line 1 - Line 2]**							**15,605,122**

Line No.	Particulars	Nalcor Exploits	Star Lake	Rattle Brook	CBPP Cogen	St. Lawrence Wind	Fermeuse Wind	Total
4	2017 Actual Power Purchases (kWh)	519,212,362	138,008,760	14,231,904	70,388,667	97,613,294	88,806,979	
5	2015 Test Year Power Purchases (kWh)	633,500,000	142,180,000	15,000,000	51,070,000	104,800,000	84,410,000	
6	2015 Test Year Cost ($/kWh)	0.04000	0.04000	0.08358	0.20132	0.06561	0.06937	
7	**B - Power Purchase Variance ($) [(Line 4 - Line 5) x Line 6)]**	**(4,571,506)**	**(166,850)**	**(64,197)**	**3,889,234**	**(471,520)**	**305,018**	**(1,079,821)**
8	**C - Holyrood TGS Fuel Costs/(Savings) ($) [(D/E)*F]**							**6,109,431**
9	**Energy Supply Cost Variance ($) [A+B+C]**							**20,634,732**
10	**Cost Variance Threshold ($)**							**500,000**
11	**Energy Supply Cost Variance Deferral ($)**							**20,134,732**
12	D - 2015 Test Year Holyrood Average Fuel Cost (bbl)							64.41
13	E - 2015 Test Year Fuel Conversion Factor (kWh/bbl)							618
14	F - Annual kWh variance - Actual vs. Test Year (kWh) (G1-G2)							58,618,668
15	G1 - 2015 Test Year Consumption (kWh)							1,042,340,000
16	G2 - 2017 Actual Consumption (kWh)							983,721,332

Appendix L
Generating Unit Operating Data

2015

2015

Hardwoods Gas Turbine Start Time	Hardwoods Gas Turbine Stop Time	Operation Time (Hours)	Reason for Operation
1/1/2015 6:11	1/1/2015 19:15	13.1	Backup due to the loss of a major generating unit
1/3/2015 6:15	1/4/2015 21:35	39.3	Support of spinning reserve
1/6/2015 6:41	1/6/2015 20:38	14.0	Support of spinning reserve
1/7/2015 16:32	1/7/2015 21:08	4.6	Support of spinning reserve
1/8/2015 10:51	1/8/2015 19:27	8.6	Support of spinning reserve
1/9/2015 6:23	1/9/2015 11:01	4.6	Planned generation outages
1/11/2015 16:49	1/11/2015 20:01	3.2	Support of spinning reserve
1/12/2015 8:07	1/12/2015 10:21	2.2	Backup due to the loss of a major generating unit
1/13/2015 15:33	1/13/2015 20:06	4.5	Support of spinning reserve
1/14/2015 6:49	1/14/2015 10:45	3.9	Support of spinning reserve
1/14/2015 16:05	1/14/2015 18:16	2.2	Support of spinning reserve
1/17/2015 13:14	1/17/2015 17:38	4.4	Support of spinning reserve
1/22/2015 9:29	1/22/2015 12:54	3.4	Support of spinning reserve
1/23/2015 9:45	1/23/2015 12:52	3.1	Testing
1/27/2015 15:12	1/27/2015 21:17	6.1	Support of spinning reserve
2/4/2015 6:55	2/4/2015 8:09	1.2	Support of spinning reserve
2/5/2015 6:46	2/5/2015 9:08	2.4	Support of spinning reserve
2/5/2015 10:21	2/5/2015 16:47	6.4	Testing
2/9/2015 6:31	2/9/2015 12:02	5.5	Support of spinning reserve
2/9/2015 15:53	2/9/2015 20:56	5.0	Support of spinning reserve
2/10/2015 6:55	2/10/2015 13:35	6.7	Support of spinning reserve
2/11/2015 8:32	2/11/2015 18:29	9.9	Support of spinning reserve
2/12/2015 6:47	2/12/2015 18:54	12.1	Support of spinning reserve
2/18/2015 11:19	2/18/2015 17:08	5.8	Testing
2/19/2015 11:38	2/19/2015 15:42	4.1	Testing
2/21/2015 10:23	2/21/2015 16:02	5.7	Testing
2/24/2015 16:50	2/24/2015 20:15	3.4	Support of spinning reserve
2/25/2015 6:36	2/25/2015 8:41	2.1	Support of spinning reserve
2/28/2015 6:37	2/28/2015 9:42	3.1	Backup due to the loss of a major generating unit
2/28/2015 10:28	2/28/2015 23:17	12.8	Backup due to the loss of a major generating unit
3/1/2015 6:25	3/1/2015 12:22	6.0	Backup due to the loss of a major generating unit
3/1/2015 16:35	3/1/2015 18:23	1.8	Backup due to the loss of a major generating unit
3/3/2015 15:08	3/3/2015 23:11	8.0	Backup due to the loss of a major generating unit
3/4/2015 6:11	3/4/2015 7:52	1.7	Backup due to the loss of a major generating unit
3/4/2015 9:27	3/4/2015 18:14	8.8	Backup due to the loss of a major generating unit
3/5/2015 11:25	3/5/2015 11:32	0.1	Testing
3/6/2015 4:10	3/6/2015 13:58	9.8	Support of spinning reserve
3/7/2015 4:02	3/7/2015 8:09	4.1	Support of spinning reserve
3/7/2015 12:57	3/7/2015 19:07	6.2	Support of spinning reserve

2015

Hardwoods Gas Turbine Start Time	Hardwoods Gas Turbine Stop Time	Operation Time (Hours)	Reason for Operation
3/8/2015 7:38	3/8/2015 8:33	0.9	Support of spinning reserve
3/9/2015 17:00	3/9/2015 20:51	3.8	Support of spinning reserve
3/10/2015 7:49	3/10/2015 8:46	0.9	Support of spinning reserve
3/10/2015 18:07	3/10/2015 20:53	2.8	Support of spinning reserve
3/12/2015 6:04	3/12/2015 11:57	5.9	Backup due to the loss of a major generating unit
3/12/2015 17:01	3/12/2015 21:26	4.4	Backup due to the loss of a major generating unit
3/13/2015 3:25	3/13/2015 12:17	8.9	Backup due to the loss of a major generating unit
3/13/2015 16:49	3/13/2015 20:38	3.8	Support of spinning reserve
3/14/2015 6:38	3/14/2015 9:27	2.8	Support of spinning reserve
3/16/2015 9:21	3/16/2015 13:20	4.0	Backup due to the loss of a major generating unit
3/17/2015 16:29	3/17/2015 16:34	0.1	Testing
3/25/2015 15:58	3/25/2015 16:08	0.2	Testing
4/2/2015 6:36	4/2/2015 8:13	1.6	Planned Avalon Peninsula transmission outages
4/13/2015 7:22	4/13/2015 8:03	0.7	Backup due to the loss of a major generating unit
4/16/2015 7:24	4/16/2015 12:49	5.4	Support of spinning reserve
4/16/2015 16:29	4/16/2015 18:19	1.8	Support of spinning reserve
4/21/2015 7:11	4/21/2015 8:41	1.5	Support of spinning reserve
4/22/2015 7:31	4/22/2015 8:45	1.2	Support of spinning reserve
5/18/2015 16:41	5/18/2015 18:07	1.4	Support of spinning reserve
5/18/2015 20:59	5/18/2015 21:49	0.8	Support of spinning reserve
7/28/2015 15:24	7/28/2015 15:49	0.4	Testing
7/28/2015 18:42	7/28/2015 18:45	0.0	Testing
7/31/2015 15:16	7/31/2015 18:09	2.9	Testing
8/1/2015 19:22	8/1/2015 22:27	3.1	Planned generation outages
8/2/2015 13:00	8/2/2015 13:52	0.9	Planned generation outages
8/2/2015 18:03	8/2/2015 23:01	5.0	Planned generation outages
8/11/2015 11:45	8/11/2015 13:01	1.3	Planned generation outages
8/11/2015 20:35	8/11/2015 20:43	0.1	Planned generation outages
8/12/2015 8:42	8/12/2015 9:53	1.2	Planned generation outages
9/8/2015 11:08	9/8/2015 13:31	2.4	Planned Avalon Peninsula transmission outages
9/8/2015 20:06	9/8/2015 22:31	2.4	Planned Avalon Peninsula transmission outages
9/15/2015 9:56	9/15/2015 11:15	1.3	Testing
9/27/2015 8:04	9/27/2015 15:51	7.8	Backup due to the loss of a major generating unit
10/9/2015 16:08	10/9/2015 16:13	0.1	Testing
10/21/2015 15:06	10/21/2015 15:08	0.0	Testing
10/23/2015 20:10	10/23/2015 20:15	0.1	Testing
11/1/2015 17:36	11/1/2015 18:26	0.8	Support of spinning reserve
11/2/2015 16:29	11/2/2015 18:58	2.5	Support of spinning reserve
11/3/2015 10:47	11/3/2015 11:07	0.3	Testing

2015

Hardwoods Gas Turbine Start Time	Hardwoods Gas Turbine Stop Time	Operation Time (Hours)	Reason for Operation
11/3/2015 19:13	11/3/2015 19:32	0.3	Planned Avalon Peninsula transmission outages
11/3/2015 20:07	11/3/2015 23:01	2.9	Planned Avalon Peninsula transmission outages
11/4/2015 13:27	11/4/2015 13:38	0.2	Testing
11/4/2015 17:12	11/4/2015 18:23	1.2	Planned Avalon Peninsula transmission outages
11/5/2015 16:00	11/5/2015 18:50	2.8	Planned Avalon Peninsula transmission outages
11/11/2015 7:26	11/11/2015 12:01	4.6	Planned Avalon Peninsula transmission outages
11/17/2015 17:00	11/17/2015 18:26	1.4	Support of spinning reserve
11/18/2015 16:00	11/18/2015 21:57	6.0	Support of spinning reserve
11/19/2015 8:54	11/19/2015 10:24	1.5	Support of spinning reserve
11/20/2015 7:23	11/20/2015 9:54	2.5	Support of spinning reserve
11/20/2015 16:29	11/20/2015 17:39	1.2	Support of spinning reserve
11/23/2015 17:31	11/23/2015 17:36	0.1	Testing
11/27/2015 11:29	11/27/2015 11:44	0.2	Testing
11/27/2015 13:57	11/27/2015 19:04	5.1	Testing
11/30/2015 15:42	11/30/2015 16:09	0.5	Support of spinning reserve
11/30/2015 16:53	11/30/2015 21:04	4.2	Support of spinning reserve
12/1/2015 7:28	12/1/2015 8:18	0.8	Support of spinning reserve
12/2/2015 11:29	12/2/2015 14:13	2.7	Backup due to the loss of a major generating unit
12/3/2015 12:49	12/3/2015 13:00	0.2	Testing
12/4/2015 16:39	12/4/2015 18:18	1.6	Support of spinning reserve
12/9/2015 12:07	12/9/2015 16:03	3.9	Backup due to the loss of a major generating unit
12/10/2015 7:13	12/10/2015 8:21	1.1	Backup due to the loss of a major generating unit
12/14/2015 16:35	12/14/2015 18:20	1.8	Backup due to the loss of a major generating unit
12/15/2015 16:35	12/15/2015 18:39	2.1	Backup due to the loss of a major generating unit
12/16/2015 16:12	12/16/2015 18:07	1.9	Backup due to the loss of a major generating unit
12/24/2015 16:15	12/24/2015 17:55	1.7	Support of spinning reserve
12/28/2015 10:40	12/28/2015 14:49	4.1	Support of spinning reserve
12/29/2015 8:17	12/29/2015 21:17	13.0	Support of spinning reserve
12/30/2015 16:35	12/30/2015 20:55	4.3	Support of spinning reserve
12/31/2015 6:48	12/31/2015 12:03	5.3	Support of spinning reserve
12/31/2015 18:07	12/31/2015 20:45	2.6	Support of spinning reserve

2015

Stephenville Gas Turbine Start Time	Stephenville Gas Turbine Stop Time	Operation Time (Hours)	Reason for Operation
1/3/2015 12:35	1/4/2015 21:23	32.8	Support of spinning reserve
1/6/2015 5:56	1/6/2015 11:27	5.5	Support of spinning reserve
1/6/2015 16:05	1/6/2015 21:56	5.9	Support of spinning reserve
1/7/2015 16:05	1/7/2015 18:55	2.8	Support of spinning reserve
1/8/2015 15:44	1/8/2015 18:49	3.1	Support of spinning reserve
1/9/2015 6:05	1/9/2015 11:22	5.3	Planned generation outages
1/12/2015 9:34	1/12/2015 10:07	0.6	Backup due to the loss of a major generating unit
1/13/2015 15:43	1/13/2015 19:22	3.6	Support of spinning reserve
1/14/2015 6:58	1/14/2015 9:42	2.7	Support of spinning reserve
1/14/2015 15:57	1/14/2015 18:27	2.5	Support of spinning reserve
1/22/2015 9:53	1/22/2015 12:47	2.9	Support of spinning reserve
1/23/2015 9:43	1/23/2015 12:45	3.0	Testing
1/27/2015 15:26	1/27/2015 19:10	3.7	Support of spinning reserve
1/29/2015 16:22	1/29/2015 17:40	1.3	Testing
1/31/2015 7:22	1/31/2015 17:00	9.6	Planned transmission outages off Avalon
2/5/2015 10:04	2/5/2015 17:54	7.8	Testing
2/9/2015 12:31	2/9/2015 21:43	9.2	Support of spinning reserve
2/10/2015 6:58	2/10/2015 12:46	5.8	Support of spinning reserve
2/11/2015 8:47	2/11/2015 18:24	9.6	Support of spinning reserve
2/12/2015 12:05	2/12/2015 14:28	2.4	Support of spinning reserve
2/18/2015 11:24	2/18/2015 17:04	5.7	Testing
2/24/2015 16:07	2/24/2015 20:12	4.1	Support of spinning reserve
2/25/2015 6:49	2/25/2015 12:55	6.1	Support of spinning reserve
2/28/2015 6:05	2/28/2015 9:15	3.2	Backup due to the loss of a major generating unit
2/28/2015 17:12	2/28/2015 20:23	3.2	Backup due to the loss of a major generating unit
3/1/2015 6:07	3/1/2015 9:42	3.6	Backup due to the loss of a major generating unit
3/1/2015 18:40	3/1/2015 21:14	2.6	Backup due to the loss of a major generating unit
3/2/2015 5:58	3/2/2015 10:35	4.6	Backup due to the loss of a major generating unit
3/3/2015 18:45	3/3/2015 21:45	3.0	Backup due to the loss of a major generating unit
3/4/2015 6:11	3/4/2015 7:15	1.1	Backup due to the loss of a major generating unit
3/4/2015 7:40	3/4/2015 13:41	6.0	Backup due to the loss of a major generating unit
3/4/2015 17:05	3/4/2015 17:59	0.9	Testing
3/4/2015 20:16	3/4/2015 20:51	0.6	Testing
3/6/2015 4:02	3/6/2015 8:18	4.3	Support of spinning reserve
3/6/2015 8:52	3/6/2015 9:00	0.1	Support of spinning reserve
3/6/2015 9:03	3/6/2015 9:10	0.1	Support of spinning reserve
3/6/2015 11:39	3/6/2015 11:44	0.1	Testing
3/7/2015 4:03	3/7/2015 8:08	4.1	Support of spinning reserve
3/12/2015 6:00	3/12/2015 8:56	2.9	Backup due to the loss of a major generating unit
5/27/2015 15:28	5/27/2015 16:10	0.7	Testing

2015

Stephenville Gas Turbine Start Time	Stephenville Gas Turbine Stop Time	Operation Time (Hours)	Reason for Operation
5/28/2015 9:41	5/28/2015 9:59	0.3	Testing
5/29/2015 7:50	5/29/2015 8:38	0.8	Testing
5/29/2015 17:26	5/29/2015 17:36	0.2	Testing
6/12/2015 9:45	6/12/2015 11:39	1.9	Testing
6/12/2015 12:01	6/12/2015 16:32	4.5	Testing
6/17/2015 17:05	6/17/2015 17:08	0.0	Testing
6/19/2015 17:23	6/19/2015 17:33	0.2	Testing
6/19/2015 19:13	6/19/2015 20:20	1.1	Testing
7/28/2015 8:58	7/28/2015 9:19	0.3	Testing
7/28/2015 9:55	7/28/2015 10:18	0.4	Testing
7/28/2015 10:56	7/28/2015 11:40	0.7	Testing
7/30/2015 11:28	7/30/2015 12:25	0.9	Testing
7/31/2015 16:21	7/31/2015 17:17	0.9	Testing
8/12/2015 20:07	8/12/2015 21:00	0.9	Testing
8/28/2015 11:12	8/28/2015 12:04	0.9	Testing
8/28/2015 12:54	8/28/2015 13:58	1.1	Testing
8/31/2015 9:35	8/31/2015 10:42	1.1	Testing
11/7/2015 16:43	11/7/2015 16:58	0.2	Testing
11/7/2015 17:29	11/7/2015 17:50	0.3	Testing
11/9/2015 15:40	11/9/2015 18:15	2.6	Testing
11/9/2015 18:35	11/9/2015 18:39	0.1	Testing
11/10/2015 11:08	11/10/2015 11:45	0.6	Testing
11/10/2015 13:10	11/10/2015 15:39	2.5	Testing
11/13/2015 10:22	11/13/2015 10:29	0.1	Testing
11/13/2015 17:31	11/13/2015 17:58	0.5	Testing
11/14/2015 17:30	11/14/2015 17:40	0.2	Testing
11/17/2015 7:40	11/17/2015 10:50	3.2	Support of spinning reserve
11/17/2015 12:49	11/17/2015 19:10	6.3	Support of spinning reserve
11/19/2015 7:10	11/19/2015 17:48	10.6	Planned transmission outages off Avalon
11/20/2015 7:39	11/20/2015 17:13	9.6	Support of spinning reserve
12/1/2015 10:01	12/1/2015 14:40	4.6	Planned transmission outages off Avalon
12/24/2015 12:04	12/24/2015 12:57	0.9	Testing
12/29/2015 16:22	12/29/2015 17:58	1.6	Support of spinning reserve

2015

St. Anthony Diesel Plant Start Time	St. Anthony Diesel Plant End Time	Operation Time (Hours)	Reason for Operation
1/2/2015 14:52	1/2/2015 15:18	0.4	Testing
1/3/2015 15:30	1/3/2015 22:08	6.6	Backup due to the loss of a major generating unit
1/4/2015 16:44	1/4/2015 21:38	4.9	Backup due to the loss of a major generating unit
1/23/2015 13:47	1/23/2015 14:54	1.1	Testing
3/4/2015 7:22	3/4/2015 12:18	4.9	Backup due to the loss of a major generating unit
3/6/2015 15:16	3/6/2015 15:42	0.4	Testing
3/17/2015 14:49	3/17/2015 15:22	0.6	Testing
4/7/2015 10:43	4/7/2015 11:47	1.1	Testing
4/8/2015 11:38	4/8/2015 17:18	5.7	Planned transmission outages off Avalon
7/25/2015 4:49	7/25/2015 6:30	1.7	Planned transmission outages off Avalon
7/28/2015 5:35	7/28/2015 13:15	7.7	Planned transmission outages off Avalon
8/13/2015 4:19	8/13/2015 12:37	8.3	Planned transmission outages off Avalon
8/16/2015 8:14	8/16/2015 16:54	8.7	Planned transmission outages off Avalon
10/3/2015 5:18	10/3/2015 13:59	8.7	Planned transmission outages off Avalon
10/20/2015 9:03	10/20/2015 17:50	8.8	Planned transmission outages off Avalon
10/28/2015 8:57	10/28/2015 16:19	7.4	Planned transmission outages off Avalon
11/17/2015 8:30	11/17/2015 13:40	5.2	Planned transmission outages off Avalon
12/8/2015 10:01	12/8/2015 10:58	0.9	Testing
12/10/2015 18:18	12/10/2015 19:04	0.8	Testing
12/17/2015 17:45	12/17/2015 18:15	0.5	Testing
12/24/2015 10:08	12/24/2015 11:10	1.0	Planned transmission outages off Avalon

Line No.	Unit	January	February	March	April	May	June	July	August	September	October	November	December
							2015						
1	Holyrood GT												
2	Energy (kWh)[1]	335,000	1,829,000	8,384,000	3,074,846	1,558,000	50,152	19,000	7,194,000	1,834,000	118,000	12,769,000	8,776,000
3	Fuel Consumption (L)	216,873	713,860	3,337,364	1,087,908	504,867	39,608	29,283	2,956,660	750,677	66,363	4,026,224	2,957,576
4	Cost ($)	-	-	2,809,865	921,223	376,296	221,667	21,879	1,995,283	449,245	43,968	2,624,150	1,943,133
5	Hardwoods GT												
6	Energy[1]	1,512,000	1,080,000	576,000	72,000	-	-	14,400	129,600	144,000	-	576,000	216,000
7	Fuel Consumption (Gal)	150,240	142,876	73,081	9,620	11,878	-	4,194	15,796	21,021	9,286	45,715	78,742
8	Cost ($)	672,812	543,994	273,328	32,756	40,444	-	12,622	46,970	62,507	26,447	131,319	223,901
9	Stephenville GT												
10	Energy[1]	640,800	820,800	86,400	-	-	86,400	36,000	36,000	21,600	-	438,480	65,520
11	Fuel Consumption (Gal)	81,189	86,025	31,914	(71)	2,048	8,782	4,917	4,493	201	(22)	43,554	11,446
12	Cost ($)	355,390	355,576	126,879	(285)	8,189	35,126	19,666	17,972	802	(89)	172,684	43,338
13	St. Anthony Diesel												
14	Energy[1]	47,342	2,952	14,436	45,682	-	-	51,071	95,390	-	160,748	35,975	8,256
15	Fuel Consumption (L)	15,663	981	4,904	14,181	129	-	15,416	29,086	311	49,619	12,483	2,072
16	Cost ($)	14,009	209	4,055	11,727	(9)	-	12,469	23,525	227	35,018	9,026	1,879
17	Hawkes Bay Disel												
18	Energy[1]	13,513	28,575	23,918	2,310	2,373	1,029	-	-	-	3,586	3,167	1,428
19	Fuel Consumption (L)	4,351	8,484	6,409	812	836	320	124	286	(35)	1,323	919	531
20	Cost ($)	4,146	7,330	5,614	716	714	56	106	244	(30)	1,130	785	453

[1] Gross Generation.

2016

2016

Hardwoods Gas Turbine Start Time	Hardwoods Gas Turbine Stop Time	Operation Time (Hours)	Reason for Operation
1/2/2016 7:41	1/2/2016 13:09	5.5	Support of spinning reserve
1/2/2016 15:43	1/2/2016 18:48	3.1	Support of spinning reserve
1/5/2016 7:14	1/5/2016 10:30	3.3	Backup due to the loss of a major generating unit
1/5/2016 16:52	1/5/2016 18:29	1.6	Backup due to the loss of a major generating unit
1/6/2016 2:00	1/9/2016 0:19	70.3	Backup due to the loss of a major generating unit
1/9/2016 8:21	1/9/2016 14:32	6.2	Backup due to the loss of a major generating unit
1/9/2016 15:51	1/9/2016 22:41	6.8	Backup due to the loss of a major generating unit
1/10/2016 9:04	1/10/2016 20:00	10.9	Backup due to the loss of a major generating unit
1/11/2016 6:52	1/11/2016 10:48	3.9	Backup due to the loss of a major generating unit
1/11/2016 14:50	1/11/2016 19:27	4.6	Backup due to the loss of a major generating unit
1/12/2016 16:53	1/12/2016 19:54	3.0	Backup due to the loss of a major generating unit
1/13/2016 7:17	1/13/2016 22:44	15.5	Backup due to the loss of a major generating unit
1/14/2016 16:00	1/14/2016 21:04	5.1	Backup due to the loss of a major generating unit
1/15/2016 8:47	1/15/2016 9:20	0.6	Backup due to the loss of a major generating unit
1/15/2016 16:35	1/15/2016 18:22	1.8	Backup due to the loss of a major generating unit
1/18/2016 16:05	1/18/2016 18:30	2.4	Backup due to the loss of a major generating unit
1/19/2016 7:15	1/19/2016 20:59	13.7	Backup due to the loss of a major generating unit
1/21/2016 7:40	1/21/2016 8:32	0.9	Backup due to the loss of a major generating unit
1/21/2016 17:08	1/21/2016 18:30	1.4	Backup due to the loss of a major generating unit
1/22/2016 5:47	1/22/2016 11:01	5.2	Backup due to the loss of a major generating unit
1/22/2016 16:09	1/22/2016 18:58	2.8	Backup due to the loss of a major generating unit
1/23/2016 16:11	1/23/2016 18:57	2.8	Backup due to the loss of a major generating unit
1/24/2016 16:47	1/24/2016 19:20	2.5	Backup due to the loss of a major generating unit
1/25/2016 7:16	1/25/2016 10:18	3.0	Backup due to the loss of a major generating unit
1/26/2016 6:00	1/26/2016 12:13	6.2	Backup due to the loss of a major generating unit
1/26/2016 16:36	1/26/2016 16:56	0.3	Backup due to the loss of a major generating unit
1/29/2016 15:06	1/29/2016 22:32	7.4	Backup due to the loss of a major generating unit
1/30/2016 17:09	1/30/2016 19:17	2.1	Backup due to the loss of a major generating unit
1/31/2016 7:40	1/31/2016 21:38	14.0	Backup due to the loss of a major generating unit
2/1/2016 16:47	2/3/2016 22:31	53.7	Backup due to the loss of a major generating unit
2/3/2016 23:48	2/6/2016 9:16	57.5	Backup due to the loss of a major generating unit
2/6/2016 11:38	2/7/2016 5:59	18.3	Backup due to the loss of a major generating unit
2/7/2016 12:27	2/9/2016 23:01	58.6	Backup due to the loss of a major generating unit
2/9/2016 23:52	2/10/2016 21:49	22.0	Backup due to the loss of a major generating unit
2/11/2016 0:58	2/12/2016 11:09	34.2	Backup due to the loss of a major generating unit
2/12/2016 13:15	2/12/2016 15:13	2.0	Backup due to the loss of a major generating unit
2/13/2016 15:53	2/13/2016 21:00	5.1	Backup due to the loss of a major generating unit
2/14/2016 9:38	2/14/2016 10:37	1.0	Backup due to the loss of a major generating unit
2/15/2016 6:27	2/15/2016 22:43	16.3	Backup due to the loss of a major generating unit
2/16/2016 6:03	2/16/2016 13:37	7.6	Backup due to the loss of a major generating unit

2016

Hardwoods Gas Turbine Start Time	Hardwoods Gas Turbine Stop Time	Operation Time (Hours)	Reason for Operation
2/16/2016 15:52	2/16/2016 20:08	4.3	Backup due to the loss of a major generating unit
2/19/2016 15:56	2/19/2016 20:56	5.0	Backup due to the loss of a major generating unit
2/20/2016 8:12	2/20/2016 9:58	1.8	Backup due to the loss of a major generating unit
2/21/2016 9:40	2/21/2016 12:15	2.6	Backup due to the loss of a major generating unit
2/23/2016 7:11	2/23/2016 8:44	1.5	Backup due to the loss of a major generating unit
2/23/2016 17:53	2/23/2016 22:28	4.6	Backup due to the loss of a major generating unit
2/24/2016 5:50	2/26/2016 9:20	51.5	Backup due to the loss of a major generating unit
2/29/2016 6:19	2/29/2016 9:04	2.8	Support of spinning reserve
3/4/2016 6:43	3/4/2016 10:59	4.3	Support of spinning reserve
3/4/2016 18:00	3/4/2016 20:36	2.6	Support of spinning reserve
3/7/2016 6:55	3/7/2016 8:30	1.6	Support of spinning reserve
3/7/2016 18:54	3/7/2016 20:51	2.0	Support of spinning reserve
3/9/2016 6:04	3/9/2016 8:58	2.9	Support of spinning reserve
3/12/2016 8:55	3/12/2016 11:30	2.6	Support of spinning reserve
3/13/2016 11:03	3/13/2016 12:31	1.5	Support of spinning reserve
3/20/2016 20:11	3/20/2016 21:29	1.3	Support of spinning reserve
3/23/2016 12:14	3/23/2016 14:34	2.3	Support of spinning reserve
3/23/2016 16:41	3/23/2016 21:48	5.1	Support of spinning reserve
3/24/2016 6:19	3/24/2016 9:18	3.0	Support of spinning reserve
3/24/2016 20:09	3/24/2016 22:50	2.7	Support of spinning reserve
3/25/2016 6:25	3/25/2016 11:28	5.1	Support of spinning reserve
3/26/2016 16:01	3/26/2016 19:17	3.3	Support of spinning reserve
4/5/2016 7:36	4/5/2016 9:32	1.9	Support of spinning reserve
4/6/2016 7:23	4/6/2016 10:26	3.0	Support of spinning reserve
4/7/2016 7:11	4/7/2016 8:52	1.7	Support of spinning reserve
4/18/2016 16:26	4/18/2016 20:22	3.9	Support of spinning reserve
4/20/2016 12:00	4/20/2016 22:07	10.1	Support of spinning reserve
4/22/2016 7:18	4/22/2016 13:57	6.7	Support of spinning reserve
4/22/2016 16:33	4/22/2016 19:11	2.6	Support of spinning reserve
4/26/2016 10:48	4/26/2016 12:37	1.8	Support of spinning reserve
5/6/2016 8:30	5/6/2016 9:46	1.3	Support of spinning reserve
5/13/2016 7:48	5/13/2016 11:06	3.3	Support of spinning reserve
5/26/2016 20:01	5/26/2016 21:55	1.9	Support of spinning reserve
5/28/2016 14:09	5/28/2016 21:53	7.7	Support of spinning reserve
6/8/2016 18:59	6/8/2016 23:29	4.5	Support of spinning reserve
6/9/2016 9:24	6/9/2016 14:44	5.3	Support of spinning reserve
6/18/2016 8:57	6/18/2016 13:08	4.2	Support of spinning reserve
7/6/2016 16:40	7/6/2016 18:52	2.2	Support of spinning reserve
7/7/2016 11:52	7/7/2016 12:52	1.0	Support of spinning reserve
7/8/2016 9:01	7/8/2016 10:34	1.5	Support of spinning reserve

2016

Hardwoods Gas Turbine Start Time	Hardwoods Gas Turbine Stop Time	Operation Time (Hours)	Reason for Operation
7/11/2016 11:58	7/11/2016 21:50	9.9	Support of spinning reserve
7/12/2016 14:21	7/12/2016 14:25	0.1	Testing
7/12/2016 16:20	7/12/2016 22:00	5.7	Support of spinning reserve
7/13/2016 8:10	7/13/2016 15:22	7.2	Support of spinning reserve
8/30/2016 14:11	8/30/2016 15:29	1.3	Testing
8/30/2016 18:02	8/30/2016 18:10	0.1	Testing
8/31/2016 12:58	8/31/2016 13:01	0.0	Testing
8/31/2016 13:56	8/31/2016 13:58	0.0	Testing
8/31/2016 16:06	8/31/2016 16:09	0.1	Testing
9/1/2016 11:01	9/1/2016 11:23	0.4	Testing
9/10/2016 7:09	9/10/2016 19:52	12.7	Planned Avalon Peninsula transmission outages
9/24/2016 19:26	9/24/2016 21:21	1.9	Planned Avalon Peninsula transmission outages
9/25/2016 10:00	9/25/2016 13:04	3.1	Planned Avalon Peninsula transmission outages
9/25/2016 19:24	9/25/2016 21:50	2.4	Planned Avalon Peninsula transmission outages
9/26/2016 16:37	9/26/2016 17:00	0.4	Testing
9/27/2016 11:01	9/27/2016 11:11	0.2	Testing
9/27/2016 12:39	9/27/2016 12:47	0.1	Testing
10/3/2016 19:05	10/3/2016 21:15	2.2	Support of spinning reserve
10/4/2016 7:08	10/4/2016 9:01	1.9	Support of spinning reserve
10/11/2016 9:25	10/11/2016 9:29	0.1	Testing
10/11/2016 22:14	10/11/2016 22:17	0.0	Testing
10/12/2016 14:32	10/12/2016 14:39	0.1	Testing
10/16/2016 19:20	10/16/2016 20:45	1.4	Support of spinning reserve
10/22/2016 14:24	10/22/2016 14:28	0.1	Testing
10/22/2016 17:02	10/22/2016 17:06	0.1	Testing
10/26/2016 14:03	10/26/2016 14:07	0.1	Testing
10/26/2016 21:16	10/26/2016 21:18	0.0	Testing
10/28/2016 7:22	10/28/2016 11:01	3.7	Support of spinning reserve
11/4/2016 11:32	11/4/2016 11:38	0.1	Testing
11/7/2016 7:16	11/7/2016 8:26	1.2	Support of spinning reserve
11/9/2016 7:14	11/9/2016 18:09	10.9	Support of spinning reserve
11/10/2016 16:38	11/10/2016 18:08	1.5	Support of spinning reserve
11/22/2016 17:22	11/22/2016 17:28	0.1	Testing
11/24/2016 17:17	11/24/2016 17:37	0.3	Testing
12/1/2016 17:13	12/1/2016 17:57	0.7	Testing
12/2/2016 10:30	12/2/2016 11:08	0.6	Testing
12/2/2016 16:50	12/2/2016 17:29	0.7	Testing
12/5/2016 9:10	12/5/2016 9:24	0.2	Testing
12/5/2016 10:30	12/5/2016 12:07	1.6	Testing
12/5/2016 16:31	12/5/2016 17:01	0.5	Testing

2016

Hardwoods Gas Turbine Start Time	Hardwoods Gas Turbine Stop Time	Operation Time (Hours)	Reason for Operation
12/6/2016 9:16	12/6/2016 18:08	8.9	Testing
12/7/2016 16:54	12/7/2016 19:05	2.2	Testing
12/8/2016 7:00	12/8/2016 18:49	11.8	Backup due to the loss of a major generating unit
12/12/2016 16:17	12/12/2016 17:47	1.5	Support of spinning reserve
12/12/2016 19:12	12/12/2016 19:43	0.5	Testing
12/14/2016 7:34	12/14/2016 10:16	2.7	Support of spinning reserve
12/14/2016 16:35	12/14/2016 19:30	2.9	Support of spinning reserve
12/16/2016 16:30	12/16/2016 21:36	5.1	Support of spinning reserve
12/17/2016 17:04	12/17/2016 22:41	5.6	Support of spinning reserve
12/26/2016 16:36	12/26/2016 17:23	0.8	Support of spinning reserve
12/27/2016 13:06	12/27/2016 18:46	5.7	Support of spinning reserve

2016

Stephenville Gas Turbine Start Time	Stephenville Gas Turbine Stop Time	Operation Time (Hours)	Reason for Operation
1/8/2016 17:03	1/8/2016 18:06	1.0	Support of spinning reserve
1/9/2016 16:39	1/9/2016 18:12	1.5	Support of spinning reserve
1/10/2016 13:47	1/10/2016 13:52	0.1	Testing
1/11/2016 22:16	1/11/2016 22:22	0.1	Testing
1/13/2016 11:40	1/13/2016 20:14	8.6	Backup due to the loss of a major generating unit
1/26/2016 6:47	1/26/2016 10:26	3.7	Backup due to the loss of a major generating unit
2/2/2016 8:10	2/2/2016 16:59	8.8	Backup due to the loss of a major generating unit
2/3/2016 5:29	2/3/2016 18:02	12.5	Backup due to the loss of a major generating unit
2/4/2016 7:52	2/4/2016 18:16	10.4	Backup due to the loss of a major generating unit
2/5/2016 8:16	2/5/2016 16:07	7.8	Backup due to the loss of a major generating unit
2/6/2016 8:36	2/6/2016 16:17	7.7	Backup due to the loss of a major generating unit
2/7/2016 13:35	2/12/2016 0:49	107.2	Backup due to the loss of a major generating unit
2/12/2016 1:27	2/12/2016 15:19	13.9	Backup due to the loss of a major generating unit
2/13/2016 16:55	2/13/2016 20:39	3.7	Backup due to the loss of a major generating unit
2/15/2016 5:55	2/15/2016 21:22	15.4	Backup due to the loss of a major generating unit
2/16/2016 5:45	2/16/2016 18:17	12.5	Backup due to the loss of a major generating unit
2/24/2016 6:50	2/24/2016 14:10	7.3	Backup due to the loss of a major generating unit
3/4/2016 9:44	3/4/2016 10:02	0.3	Testing
3/10/2016 11:18	3/10/2016 11:20	0.0	Testing
3/26/2016 15:12	3/26/2016 19:19	4.1	Support of spinning reserve
5/28/2016 14:07	5/28/2016 21:29	7.4	Support of spinning reserve
7/29/2016 16:22	7/29/2016 21:28	5.1	Testing
7/30/2016 8:54	7/30/2016 11:48	2.9	Testing
8/18/2016 20:13	8/18/2016 20:35	0.4	Testing
8/19/2016 6:10	8/19/2016 6:33	0.4	Testing
8/19/2016 7:25	8/19/2016 7:49	0.4	Testing
9/23/2016 14:07	9/23/2016 15:44	1.6	Testing
9/26/2016 13:53	9/26/2016 19:44	5.9	Planned transmission outages off Avalon
9/27/2016 7:15	9/27/2016 20:59	13.7	Planned transmission outages off Avalon
9/28/2016 7:16	9/28/2016 20:45	13.5	Planned transmission outages off Avalon
9/29/2016 7:14	9/29/2016 16:53	9.7	Planned transmission outages off Avalon
10/13/2016 13:18	10/13/2016 19:28	6.2	Planned generation outages
12/2/2016 18:56	12/2/2016 18:58	0.0	Testing
12/3/2016 7:49	12/3/2016 8:14	0.4	Testing
12/3/2016 10:48	12/3/2016 11:05	0.3	Testing
12/8/2016 9:08	12/8/2016 9:17	0.1	Testing
12/8/2016 12:50	12/8/2016 13:11	0.4	Testing
12/9/2016 14:24	12/9/2016 17:32	3.1	Testing
12/10/2016 10:07	12/10/2016 11:08	1.0	Testing
12/10/2016 14:20	12/10/2016 19:58	5.6	Testing

2016

Stephenville Gas Turbine Start Time	Stephenville Gas Turbine Stop Time	Operation Time (Hours)	Reason for Operation
12/14/2016 7:20	12/14/2016 9:44	2.4	Support of spinning reserve
12/15/2016 11:44	12/15/2016 13:01	1.3	Testing
12/17/2016 16:45	12/17/2016 18:32	1.8	Support of spinning reserve
12/21/2016 14:26	12/21/2016 15:35	1.1	Testing
12/23/2016 8:20	12/23/2016 8:42	0.4	Testing
12/27/2016 16:49	12/27/2016 18:10	1.4	Support of spinning reserve

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St. Anthony Diesel Plant Start Time	St. Anthony Diesel Plant End Time	Operation Time (Hours)	Reason for Operation
1/13/2016 9:10	1/13/2016 11:46	2.6	Testing
1/15/2016 11:00	1/15/2016 11:38	0.6	Testing
1/29/2016 13:14	1/29/2016 15:13	2.0	Testing
2/3/2016 5:13	2/3/2016 9:15	4.0	Backup due to the loss of a major generating unit
2/24/2016 10:35	2/24/2016 10:46	0.2	Testing
3/4/2016 11:12	3/4/2016 13:20	2.1	Testing
3/14/2016 15:33	3/14/2016 15:36	0.0	Testing
3/15/2016 11:45	3/15/2016 11:50	0.1	Testing
3/16/2016 8:06	3/16/2016 15:53	7.8	Planned transmission outages off Avalon
3/17/2016 5:46	3/17/2016 22:12	16.4	Planned transmission outages off Avalon
3/22/2016 22:13	3/25/2016 20:00	69.8	Backup due to the loss of area transmission line
3/28/2016 18:06	3/28/2016 19:44	1.6	Planned transmission outages off Avalon
3/28/2016 19:57	3/28/2016 21:13	1.3	Planned transmission outages off Avalon
5/5/2016 13:01	5/5/2016 14:30	1.5	Testing
5/26/2016 12:59	5/26/2016 13:29	0.5	Testing
7/29/2016 6:08	7/29/2016 6:58	0.8	Backup due to the loss of area transmission line
7/29/2016 7:27	7/29/2016 10:09	2.7	Backup due to the loss of area transmission line
7/29/2016 10:14	7/29/2016 12:48	2.6	Backup due to the loss of area transmission line
8/2/2016 13:04	8/2/2016 13:12	0.1	Testing
8/2/2016 13:21	8/2/2016 13:27	0.1	Testing
9/6/2016 13:59	9/6/2016 15:42	1.7	Testing
8/22/2016 11:05	8/22/2016 12:55	1.8	Testing
8/30/2016 15:05	8/30/2016 15:26	0.4	Testing
9/2/2016 13:55	9/2/2016 14:32	0.6	Testing
9/7/2016 13:25	9/7/2016 13:49	0.4	Planned transmission outages off Avalon
9/11/2016 6:28	9/11/2016 6:42	0.2	Planned transmission outages off Avalon
9/11/2016 6:48	9/11/2016 16:36	9.8	Planned transmission outages off Avalon
10/7/2016 9:22	10/7/2016 13:51	4.5	Testing
10/15/2016 15:51	10/15/2016 17:02	1.2	Testing
10/16/2016 6:21	10/16/2016 13:00	6.7	Planned transmission outages off Avalon
10/17/2016 9:37	10/17/2016 10:24	0.8	Testing
10/18/2016 15:24	10/18/2016 15:27		Testing
10/24/2016 14:01	10/24/2016 14:15		Testing
11/17/2016 13:19	11/17/2016 14:37	1.3	Planned transmission outages off Avalon
11/24/2016 9:46	11/24/2016 14:31	4.7	Planned transmission outages off Avalon
11/27/2016 22:53	11/27/2016 23:24	0.5	Backup due to the loss of area transmission line
11/27/2016 23:39	11/28/2016 18:26	18.8	Backup due to the loss of area transmission line

		2016											
Line No.	**Unit**	**January**	**February**	**March**	**April**	**May**	**June**	**July**	**August**	**September**	**October**	**November**	**December**
1	Holyrood GT												
2	Energy (kWh)[1]	40,585,000	40,145,000	5,543,000	6,801,000	664,000	47,000	-	-	3,403,000	915,000	1,431,000	13,372,000
3	Fuel Consumption (L)	14,372,884	14,043,370	2,121,413	2,585,302	285,509	31,006	125	(4,623)	1,408,437	378,739	594,866	4,650,062
4	Cost ($)	8,146,933	7,911,127	1,188,424	1,478,796	157,093	17,093	70	(2,581)	789,573	212,322	343,629	3,080,556
5	Hardwoods GT												
6	Energy[1]	3,240,000	7,848,000	432,000	504,000	72,000	144,000	144,000	-	72,000	72,000	72,000	648,000
7	Fuel Consumption (Gal)	353,306	679,713	51,807	52,682	16,498	13,198	20,858	2,488	7,366	7,187	6,475	72,774
8	Cost ($)	1,004,612	1,738,906	130,796	133,251	41,728	33,383	52,757	6,292	18,631	18,178	16,378	191,158
9	Stephenville GT												
10	Energy[1]	110,160	4,713,880	21,114	-	36,742	-	61,960	9,706	238,417	42,934	-	209,876
11	Fuel Consumption (Gal)	12,504	426,045	14,054	(10,945)	2,911	103	(244)	11,843	27,482	12,581	733	21,002
12	Cost ($)	46,964	1,371,543	45,498	(35,456)	9,362	331	(785)	38,092	88,391	40,466	2,356	68,247
13	St. Anthony Diesel												
14	Energy[1]	20,863	21,377	386,150	1,166	1,253	965	13,149	3,632	74,072	55,684	104,661	-
15	Fuel Consumption (L)	7,886	7,023	125,357	304	25	25	5,726	1,182	24,010	16,704	32,035	(185)
16	Cost ($)	5,651	4,913	77,863	196	258	73	3,556	734	14,909	10,285	20,902	(134)
17	Hawkes Bay Disel												
18	Energy[1]	4,290	18,834	290,369	233	561	-	1,323	11,230	1,372	7,177	67,057	14,854
19	Fuel Consumption (L)	1,442	5,134	79,263	172	-	-	188	3,125	5,280	3,880	18,133	3,988
20	Cost ($)	1,231	4,383	53,313	120	2,293	609	127	2,103	3,553	14,594	12,237	2,755

[1] Gross Generation.

2017

2017

Stephenville Gas Turbine Start Time	Stephenville Gas Turbine Stop Time	Operation Time (Hours)	Reason for Operation
1/11/2017 16:19	1/11/2017 17:39	1.3	Support of spinning reserve
1/12/2017 9:29	1/12/2017 10:04	0.6	Testing
1/12/2017 11:44	1/12/2017 13:21	1.6	Testing
1/24/2017 9:30	1/24/2017 11:22	1.9	Testing
2/3/2017 11:08	2/3/2017 12:38	1.5	Testing
2/5/2017 17:43	2/5/2017 20:55	3.2	Support of spinning reserve
2/6/2017 14:38	2/6/2017 18:55	4.3	Support of spinning reserve
2/7/2017 6:47	2/7/2017 12:38	5.9	Support of spinning reserve
2/7/2017 15:12	2/7/2017 22:12	7.0	Support of spinning reserve
2/8/2017 6:31	2/8/2017 14:02	7.5	Support of spinning reserve
2/8/2017 15:51	2/8/2017 19:09	3.3	Support of spinning reserve
2/13/2017 9:39	2/13/2017 12:43	3.1	Support of spinning reserve
2/13/2017 15:49	2/13/2017 20:59	5.2	Support of spinning reserve
2/14/2017 5:24	2/14/2017 20:27	15.0	Support of spinning reserve
3/11/2017 17:04	3/11/2017 23:53	6.8	Support of spinning reserve
3/12/2017 7:16	3/12/2017 18:12	10.9	Support of spinning reserve
3/17/2017 12:46	3/17/2017 13:11	0.4	Testing
3/27/2017 7:12	3/27/2017 9:17	2.1	Support of spinning reserve
4/26/2017 13:15	4/26/2017 13:33	0.3	Testing
5/15/2017 16:49	5/15/2017 17:52	1.0	Testing
5/16/2017 18:03	5/16/2017 18:43	0.7	Testing
5/17/2017 13:37	5/17/2017 14:19	0.7	Testing
6/21/2017 7:45	6/21/2017 8:06	0.4	Planned transmission outages
6/22/2017 18:16	6/22/2017 18:58	0.7	Testing
6/23/2017 8:03	6/23/2017 12:01	4.0	Planned transmission outages
9/7/2017 14:49	9/7/2017 15:31	0.7	Testing
11/11/2017 16:11	11/11/2017 17:16	1.1	Support of spinning reserve
11/13/2017 16:52	11/13/2017 23:17	6.4	Support of spinning reserve
11/14/2017 1:11	11/14/2017 1:13	-	Testing
11/14/2017 7:30	11/14/2017 12:44	5.2	Support of spinning reserve
11/15/2017 16:20	11/15/2017 19:54	3.6	Support of spinning reserve
11/17/2017 16:25	11/17/2017 17:32	1.1	Support of spinning reserve
11/21/2017 11:26	11/21/2017 11:32	0.1	Testing
11/21/2017 16:36	11/21/2017 18:07	1.5	Support of spinning reserve
11/22/2017 13:49	11/22/2017 14:25	0.6	Testing
11/30/2017 15:04	11/30/2017 15:38	0.6	Testing
12/1/2017 7:23	12/1/2017 10:57	3.6	Support of spinning reserve
12/1/2017 16:33	12/1/2017 18:14	1.7	Support of spinning reserve
12/2/2017 6:56	12/2/2017 9:15	2.3	Support of spinning reserve
12/6/2017 16:37	12/6/2017 17:46	1.1	Support of spinning reserve
12/18/2017 16:30	12/18/2017 16:36	0.1	Support of spinning reserve
12/18/2017 17:20	12/18/2017 17:49	0.5	Support of spinning reserve
12/27/2017 9:11	12/27/2017 18:47	9.6	Support of spinning reserve

12/28/2017 10:36	12/28/2017 14:23	3.8	Testing
12/28/2017 16:27	12/28/2017 20:40	4.2	Support of spinning reserve
12/30/2017 16:32	12/30/2017 19:05	2.6	Support of spinning reserve

2017

Hardwoods Gas Turbine Start Time	Hardwoods Gas Turbine Stop Time	Operation Time (Hours)	Reason for Operation
1/4/2017 16:44	1/4/2017 18:53	2.2	Support of spinning reserve
1/7/2017 16:46	1/7/2017 19:02	2.3	Support of spinning reserve
1/10/2017 8:23	1/10/2017 8:51	0.5	Support of spinning reserve
1/13/2017 17:09	1/13/2017 17:39	0.5	Testing
1/14/2017 16:04	1/14/2017 20:01	3.9	Support of spinning reserve
1/15/2017 9:08	1/15/2017 12:47	3.6	Support of spinning reserve
1/16/2017 17:07	1/16/2017 18:07	1.0	Support of spinning reserve
1/17/2017 6:49	1/17/2017 9:16	2.4	Support of spinning reserve
1/19/2017 8:01	1/19/2017 9:12	1.2	Support of spinning reserve
1/21/2017 17:28	1/21/2017 19:06	1.6	Support of spinning reserve
1/22/2017 17:04	1/22/2017 18:29	1.4	Support of spinning reserve
1/24/2017 7:17	1/24/2017 8:52	1.6	Support of spinning reserve
1/24/2017 17:24	1/24/2017 18:55	1.5	Support of spinning reserve
1/25/2017 7:09	1/25/2017 10:00	2.8	Support of spinning reserve
2/1/2017 16:53	2/1/2017 20:45	3.9	Support of spinning reserve
2/2/2017 6:55	2/2/2017 9:26	2.5	Support of spinning reserve
2/2/2017 16:32	2/2/2017 20:57	4.4	Support of spinning reserve
2/3/2017 6:51	2/3/2017 10:22	3.5	Support of spinning reserve
2/3/2017 17:23	2/3/2017 19:19	1.9	Support of spinning reserve
2/4/2017 6:45	2/4/2017 7:46	1.0	Support of spinning reserve
2/5/2017 8:22	2/5/2017 12:48	4.4	Support of spinning reserve
2/5/2017 15:45	2/6/2017 0:17	8.5	Support of spinning reserve
2/6/2017 6:41	2/6/2017 7:18	0.6	Support of spinning reserve
2/6/2017 13:19	2/6/2017 14:25	1.1	Support of spinning reserve
2/11/2017 14:42	2/11/2017 15:18	0.6	Support of spinning reserve
2/19/2017 11:01	2/19/2017 12:38	1.6	Testing
2/23/2017 7:05	2/23/2017 8:38	1.5	Support of spinning reserve
3/1/2017 8:29	3/1/2017 9:57	1.5	Support of spinning reserve
3/4/2017 17:37	3/4/2017 20:28	2.9	Support of spinning reserve
3/5/2017 7:46	3/5/2017 10:43	3.0	Support of spinning reserve
3/7/2017 7:09	3/7/2017 7:45	0.6	Support of spinning reserve
3/12/2017 11:55	3/12/2017 23:42	11.8	Support of spinning reserve
3/15/2017 8:56	3/15/2017 12:57	4.0	Support of spinning reserve
3/20/2017 13:38	3/20/2017 16:37	3.0	Testing
3/25/2017 6:40	3/25/2017 8:45	2.1	Support of spinning reserve
3/27/2017 6:29	3/27/2017 14:53	8.4	Support of spinning reserve
3/28/2017 7:19	3/28/2017 8:26	1.1	Support of spinning reserve
3/29/2017 7:07	3/29/2017 9:26	2.3	Support of spinning reserve
3/30/2017 10:47	3/30/2017 13:22	2.6	Support of spinning reserve
3/31/2017 16:09	3/31/2017 20:28	4.3	Support of spinning reserve
4/13/2017 7:49	4/13/2017 10:30	2.7	Support of spinning reserve
4/15/2017 8:10	4/15/2017 12:06	3.9	Support of spinning reserve
4/17/2017 8:43	4/17/2017 14:48	6.1	Support of spinning reserve
4/18/2017 7:11	4/18/2017 12:58	5.8	Support of spinning reserve

4/19/2017 7:34	4/19/2017 9:37	2.0	Support of spinning reserve
4/20/2017 12:07	4/20/2017 14:07	2.0	Support of spinning reserve
4/20/2017 15:48	4/20/2017 22:03	6.2	Support of spinning reserve
4/21/2017 15:10	4/21/2017 22:01	6.8	Support of spinning reserve
4/22/2017 8:39	4/22/2017 13:17	4.6	Support of spinning reserve
5/1/2017 7:21	5/1/2017 10:35	3.2	Support of spinning reserve
5/1/2017 14:06	5/1/2017 22:42	8.6	Support of spinning reserve
5/2/2017 6:16	5/2/2017 8:52	2.6	Support of spinning reserve
5/3/2017 6:39	5/3/2017 7:08	0.5	Support of spinning reserve
5/17/2017 10:20	5/17/2017 12:59	2.7	Planned transmission outages
5/21/2017 9:49	5/21/2017 13:40	3.8	Support of spinning reserve
5/22/2017 9:41	5/22/2017 14:01	4.3	Support of spinning reserve
5/22/2017 16:22	5/22/2017 21:33	5.2	Support of spinning reserve
5/24/2017 10:27	5/24/2017 12:56	2.5	Planned transmission outages
5/25/2017 7:32	5/25/2017 10:26	2.9	Support of spinning reserve
5/26/2017 7:15	5/26/2017 9:26	2.2	Support of spinning reserve
5/29/2017 7:34	5/29/2017 8:46	1.2	Planned transmission outages
6/3/2017 17:18	6/3/2017 22:19	5.0	Support of spinning reserve
6/5/2017 19:03	6/5/2017 22:06	3.0	Support of spinning reserve
6/6/2017 6:54	6/6/2017 12:59	6.1	Support of spinning reserve
6/7/2017 7:14	6/7/2017 9:21	2.1	Support of spinning reserve
6/8/2017 7:25	6/8/2017 9:40	2.3	Support of spinning reserve
7/25/2017 10:28	7/25/2017 10:47	0.3	Testing
7/30/2017 10:09	7/30/2017 11:06	0.9	Support of spinning reserve
8/11/2017 13:31	8/11/2017 13:42	0.2	Testing
8/17/2017 11:26	8/17/2017 11:36	0.2	Testing
8/17/2017 13:16	8/17/2017 13:33	0.3	Testing
8/25/2017 9:44	8/25/2017 13:55	4.2	Support of spinning reserve
8/26/2017 13:06	8/26/2017 13:28	0.4	Testing
8/26/2017 15:00	8/26/2017 15:09	0.1	Testing
8/26/2017 15:00	8/26/2017 15:09	0.1	Testing
8/27/2017 8:55	8/27/2017 9:24	0.5	Testing
8/27/2017 12:02	8/27/2017 13:46	1.7	Support of spinning reserve
9/21/2017 16:44	9/21/2017 18:30	1.8	Testing
9/22/2017 8:40	9/22/2017 9:02	0.4	Testing
9/22/2017 9:32	9/22/2017 9:46	0.2	Testing
10/22/2017 16:23	10/22/2017 21:52	5.5	Planned transmission outage
10/23/2017 6:38	10/23/2017 9:53	3.3	Planned transmission outage
10/31/2017 7:10	10/31/2017 11:16	4.1	Support of spinning reserve
10/31/2017 16:26	10/31/2017 18:47	2.3	Support of spinning reserve
11/8/2017 17:00	11/8/2017 18:14	1.2	Support of spinning reserve
11/9/2017 16:01	11/9/2017 18:26	2.4	Support of spinning reserve
11/11/2017 16:21	11/11/2017 17:24	1.0	Support of spinning reserve
11/20/2017 15:58	11/20/2017 16:09	0.2	Testing
11/20/2017 17:30	11/20/2017 18:16	0.8	Testing
11/21/2017 12:35	11/21/2017 13:18	0.7	Testing
11/21/2017 16:10	11/21/2017 19:47	3.6	Support of spinning reserve
11/22/2017 7:18	11/22/2017 8:58	1.7	Support of spinning reserve
11/24/2017 16:28	11/24/2017 17:25	0.9	Support of spinning reserve

12/1/2017 6:55	12/1/2017 12:07	5.2	Support of spinning reserve
12/1/2017 16:27	12/1/2017 19:09	2.7	Support of spinning reserve
12/2/2017 7:16	12/2/2017 10:13	3.0	Support of spinning reserve
12/2/2017 12:48	12/2/2017 12:55	0.1	Testing
12/2/2017 16:34	12/2/2017 18:22	1.8	Support of spinning reserve
12/3/2017 16:00	12/3/2017 19:48	3.8	Support of spinning reserve
12/5/2017 16:14	12/5/2017 17:33	1.3	Support of spinning reserve
12/7/2017 15:40	12/7/2017 16:15	0.6	Testing
12/17/2017 16:40	12/17/2017 18:28	1.8	Support of spinning reserve
12/18/2017 16:20	12/18/2017 17:46	1.4	Support of spinning reserve
12/21/2017 11:59	12/21/2017 12:28	0.5	Testing
12/21/2017 14:09	12/21/2017 14:46	0.6	Testing
12/21/2017 18:17	12/21/2017 18:21	0.1	Testing
12/22/2017 16:50	12/22/2017 17:28	0.6	Support of spinning reserve
12/23/2017 16:47	12/23/2017 17:59	1.2	Support of spinning reserve
12/27/2017 7:20	12/27/2017 22:32	15.2	Support of spinning reserve
12/28/2017 7:06	12/28/2017 19:13	12.1	Support of spinning reserve
12/28/2017 23:13	12/28/2017 23:20	0.1	Support of spinning reserve
12/29/2017 16:24	12/29/2017 19:57	3.6	Support of spinning reserve
12/30/2017 8:54	12/30/2017 13:18	4.4	Support of spinning reserve
12/30/2017 16:13	12/30/2017 20:32	4.3	Support of spinning reserve

2017

Hawke's Bay Diesel Plant Start Time	Hawke's Bay Diesel Plant Stop Time	Operation Time (Hours)	Reason for Operation
1/16/2017 8:59	1/16/2017 9:27	0.5	Testing
2/1/2017 14:51	2/1/2017 14:59	0.1	Testing
2/1/2017 15:02	2/1/2017 15:08	0.1	Testing
2/7/2017 7:26	2/7/2017 8:58	1.5	Support of spinning reserve
2/7/2017 16:05	2/7/2017 20:07	4.0	Support of spinning reserve
2/8/2017 5:56	2/8/2017 10:28	4.5	Support of spinning reserve
2/8/2017 16:45	2/8/2017 17:17	0.5	Support of spinning reserve
2/13/2017 8:45	2/13/2017 12:31	3.8	Support of spinning reserve
2/13/2017 16:19	2/13/2017 21:35	5.3	Support of spinning reserve
2/14/2017 10:45	2/14/2017 13:44	3.0	Support of spinning reserve
3/12/2017 12:01	3/12/2017 18:23	6.4	Support of spinning reserve
4/19/2017 10:37	4/19/2017 10:52	0.2	Testing
4/19/2017 15:18	4/19/2017 15:20	-	Testing
4/20/2017 10:45	4/20/2017 10:49	0.1	Testing
4/24/2017 17:22	4/24/2017 17:38	0.3	Testing
4/24/2017 18:07	4/24/2017 18:18	0.2	Testing
5/19/2017 15:24	5/19/2017 15:44	0.3	Testing
6/19/2017 13:46	6/19/2017 13:57	0.2	Testing
8/7/2017 13:43	8/7/2017 14:05	0.4	Testing
9/2/2017 10:10	9/2/2017 10:43	0.6	Testing
9/3/2017 8:33	9/3/2017 8:50	0.3	Testing
9/4/2017 17:56	9/4/2017 18:03	0.1	Testing
10/28/2017 14:13	10/28/2017 14:26	0.2	Testing
10/28/2017 14:45	10/28/2017 14:52	0.1	Testing
11/23/2017 9:17	11/23/2017 14:40	5.4	Support of spinning reserve
12/27/2017 16:36	12/27/2017 21:39	5.1	Support of spinning reserve

2017

St. Anthony Diesel Plant Start Time	St. Anthony Diesel Plant Stop Time	Operation Time (Hours)	Reason for Operation
1/16/2017 11:23	1/16/2017 13:11	1.8	Testing
1/24/2017 14:06	1/24/2017 14:27	0.3	Testing
2/4/2017 12:48	2/4/2017 13:57	1.2	Testing
2/4/2017 14:06	2/4/2017 14:13	0.1	Testing
2/4/2017 15:12	2/4/2017 15:22	0.2	Testing
2/7/2017 7:19	2/7/2017 8:56	1.6	Support of spinning reserve
2/7/2017 15:58	2/7/2017 20:22	4.4	Support of spinning reserve
2/8/2017 6:03	2/8/2017 10:40	4.6	Support of spinning reserve
2/13/2017 9:42	2/13/2017 12:31	2.8	Support of spinning reserve
2/13/2017 16:20	2/13/2017 21:41	5.3	Support of spinning reserve
2/21/2017 15:30	2/21/2017 15:46	0.3	Testing
2/22/2017 15:17	2/22/2017 15:30	0.2	Testing
2/22/2017 15:32	2/22/2017 15:59	0.5	Testing
3/12/2017 10:05	3/12/2017 18:23	8.3	Support of spinning reserve
5/1/2017 12:52	5/1/2017 15:00	2.1	Support of spinning reserve
5/1/2017 20:45	5/1/2017 21:00	0.2	Testing
6/23/2017 9:25	6/23/2017 11:30	2.1	Testing
7/5/2017 4:30	7/5/2017 11:55	7.4	Planned transmission outages
8/16/2017 8:34	8/16/2017 18:36	10.0	Planned transmission outages
8/30/2017 6:22	8/30/2017 13:58	7.6	Planned transmission outages
9/11/2017 12:47	9/11/2017 17:56	5.2	Planned transmission outages
11/23/2017 9:19	11/23/2017 14:44	5.4	Support of spinning reserve
11/24/2017 12:29	11/24/2017 13:58	1.5	Planned transmission outages
11/30/2017 9:08	11/30/2017 14:51	5.7	Planned transmission outages

2017

Holyrood Diesels Start Time	Holyrood Diesels Stop Time	Operation Time (Hours)	Reason for Operation
1/12/2017 10:50	1/12/2017 12:15	1.4	Testing
2/6/2017 15:15	2/6/2017 19:10	3.9	Testing
2/7/2017 5:50	2/7/2017 10:23	4.5	Support of spinning reserve
2/7/2017 15:33	2/7/2017 22:02	6.5	Support of spinning reserve
2/8/2017 5:28	2/8/2017 12:45	7.3	Support of spinning reserve
2/8/2017 16:03	2/8/2017 19:27	3.4	Support of spinning reserve
2/13/2017 9:00	2/13/2017 12:43	3.7	Support of spinning reserve
2/13/2017 15:55	2/13/2017 23:59	8.1	Support of spinning reserve
2/14/2017 7:17	2/14/2017 20:01	12.7	Support of spinning reserve
2/20/2017 9:15	2/20/2017 9:35	0.3	Testing
3/27/2017 6:30	3/27/2017 9:20	2.8	Support of spinning reserve
5/1/2017 9:20	5/1/2017 10:25	1.1	Support of spinning reserve
5/3/2017 7:20	5/3/2017 8:17	0.9	Support of spinning reserve
5/23/2017 16:00	5/23/2017 16:15	0.3	Testing
10/23/2017 11:21	10/23/2017 11:43	0.4	Support of spinning reserve
11/15/2017 17:05	11/15/2017 18:15	1.2	Support of spinning reserve
11/24/2017 15:30	11/24/2017 16:00	0.5	Testing
12/18/2017 16:45	12/18/2017 17:25	0.7	Support of spinning reserve
12/27/2017 10:33	12/27/2017 23:05	12.5	Support of spinning reserve
12/28/2017 9:30	12/28/2017 12:51	3.3	Support of spinning reserve
12/28/2017 16:11	12/28/2017 18:01	1.8	Support of spinning reserve

		2017											
Line No.	**Unit**	**January**	**February**	**March**	**April**	**May**	**June**	**July**	**August**	**September**	**October**	**November**	**December**
1	Holyrood GT												
2	Energy (kWh)[1]	7,248,000	10,377,000	9,525,000	2,889,000	2,735,000	341,000	1,545,000	9,236,000	-	3,899,000	6,926,000	10,059,000
3	Fuel Consumption (L)	2,786,173	3,680,376	3,633,492	1,102,155	2,073,547	103,209	38,691	4,355,580	-	1,550,837	3,201,944	3,232,048
4	Cost ($)	1,981,173	2,574,505	2,492,177	757,890	691,925	70,502	26,096	2,847,953	-	978,161	2,234,334	2,530,242
5	Hardwoods GT												
6	Energy[1]	325,000	648,000	468,000	468,000	540,000	288,000	-	72,000	72,000	72,000	216,000	864,000
7	Fuel Consumption (Gal)	35,553	65,328	60,899	57,114	52,068	34,870	975	8,260	2,847	21,815	38,296	76,234
8	Cost ($)	101,411	190,254	177,357	166,333	151,636	101,553	2,840	24,056	8,290	63,530	111,529	222,359
9	Stephenville GT												
10	Energy[1]	65,822	599,540	280,253	1,724	28,951	44,683	4	-	7,207	-	109,073	194,656
11	Fuel Consumption (Gal)	6,712	75,506	29,935	228	3,397	5,287	(80)	240	971	257	16,316	25,756
12	Cost ($)	21,941	246,826	98,502	757	11,278	17,554	(265)	796	3,224	852	54,170	85,512
13	St. Anthony Diesel	3.27	3.27	3.29	3.32	3.32	3.32	3.32	3.32	3.32	3.32	3.32	3.32
14	Energy[1]	5,578	101,141	28,216	-	7,555	11,066	51,341	96,680	33,489	-	56,477	2,914
15	Fuel Consumption (L)	1,906	30,618	8,412	158	2,242	4,193	15,735	28,406	10,081	-	16,593	1,367
16	Cost ($)	1,274	21,040	5,791	(147)	1,544	2,888	10,838	19,108	6,938	(55)	11,399	939
17	Hawkes Bay Disel												
18	Energy[1]	1,505	95,569	15,511	954	342	317	1	1,036	-	-	-	19,206
19	Fuel Consumption (L)	592	26,340	5,120	499	174	40	32	446	2,008	3,758	5,799	5,988
20	Cost ($)	2,011	18,430	3,610	276	120	28	22	308	1,387	2,596	4,006	4,346

[1] Gross generation

Appendix M
2015 Holyrood Conversion Deferral

Holyrood Conversion Rate Deferral Account
December 31, 2015

Particulars		Efficiency Factor (kWh/bbl)
A - 2015 Actual quantity of No.6 fuel consumed (bbl)	2,423,336	602
B - Calculated quantity of No. 6 fuel consumed using the 2015 Test Year Cost of Service fuel conversion rate (bbl) [1]	2,359,960	618
C - 2015 Test Year Cost of Service No. 6 fuel cost ($ per bbl)	64.41	
Holyrood Fuel Conversion Rate Variance ($) [(A - B) x C]	4,082,048	
Cost Variance Threshold ($)	500,000	
Holyrood Fuel Conversion Rate Deferral Balance ($)	**3,582,048**	
[1] Calculation of B (D/E):		
D - 2015 Actual net Holyrood production (kWh)	1,458,455,118	
E - 2015 Test Year Cost of Service fuel conversion rate (kWh/bbl)	618	

Appendix N
2016 Holyrood Conversion Deferral

Holyrood Conversion Rate Deferral Account
December 31, 2016

Particulars		Efficiency Factor (kWh/bbl)
A - 2016 Actual quantity of No.6 fuel consumed (bbl)	2,664,019	608
B - Calculated quantity of No. 6 fuel consumed using the 2015 Test Year Cost of Service fuel conversion rate (bbl) [1]	2,622,866	618
C - 2015 Test Year Cost of Service No. 6 fuel cost ($ per bbl)	64.41	
Holyrood Fuel Conversion Rate Variance ($) [(A - B) x C]	2,650,665	
Cost Variance Threshold ($)	500,000	
Holyrood Fuel Conversion Rate Deferral Balance ($)	**2,150,665**	

[1] Calculation of B (D/E):

D - 2016 Actual net Holyrood production (kWh)	1,620,931,383	
E - 2015 Test Year Cost of Service fuel conversion rate (kWh/bbl)	618	

Appendix O
2017 Holyrood Conversion Deferral

Holyrood Conversion Rate Deferral Account
December 31, 2017

Particulars		Efficiency Factor (kWh/bbl)
A - 2017 Actual quantity of No.6 fuel consumed (bbl)	2,776,834	602
B - Calculated quantity of No. 6 fuel consumed using the 2015 Test Year Cost of Service fuel conversion rate (bbl) [1]	2,704,426	618
C - 2015 Test Year Cost of Service No. 6 fuel cost ($ per bbl)	64.41	
Holyrood Fuel Conversion Rate Variance ($) [(A - B) x C]	4,663,799	
Cost Variance Threshold ($)	500,000	
Holyrood Fuel Conversion Rate Deferral Balance ($)	**4,163,799**	

[1] Calculation of B (D/E):

D - 2017 Actual net Holyrood production (kWh)	1,671,335,288	
E - 2015 Test Year Cost of Service fuel conversion rate (kWh/bbl)	618	