newfoundland labrador
hydro
a nalcor energy company

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November 27, 2017

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

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

Dear Ms. Blundon:

Re: 2017 General Rate Application (Revision 4 – November 24, 2017)

Enclosed with this letter are the original and 13 copies of Revision 4 to Newfoundland and Labrador Hydro's (Hydro) 2017 General Rate Application (the Application) for approval of Hydro's 2018 and 2019 forecast costs and customer rates.

This Revision 4 contains revisions to:

- Hydro's Application;
- Chapter 1 – *Overview*;
- Chapter 3 – *Operations*;
- Chapter 5 – *Rates and Regulations*;
- Exhibit 1 – *Provincial Electrical System;*
- Exhibit 14 – *2018 Test Year Cost of Service Study;*
- Exhibit 15 – *2019 Test Year Cost of Service Study;*
- Exhibit 16 – *Interim Rates, Rules and Regulations*; and
- Exhibit 17 – *Final Rates, Rules and Regulations.*

For ease of convenience, Hydro has included a table with this letter indicating where each revision is located.

These revisions are a result of revised Cost of Service studies for both 2018 and 2019. Changes made to these studies are as follows:

- A revision in the calculation of specifically assigned charges as a result of correcting an error as noted in request for information NP-NLH-261;
- A change in the asset coding of breaker disconnects from specifically assigned to common for both Newfoundland Power and Vale;
- A change in the coding of contributions in aid of construction associated with the integration of Muskrat Falls assets, which was incorrectly credited to rural assets; and

- A change to the interconnected system energy losses in the 2018 and 2019 Cost of Service studies in order to ensure consistency with Hydro's forecast load requirements, as provided in Chapter 3 of Hydro's evidence.

The impacts of the above noted changes on the resulting revenue requirements of Hydro's customers are noted in Table 1.

Table 1 – Revenue Requirement Impacts

Particulars ($)	2018 Test Year	2019 Test Year
	Increase/(Decrease) in Revenue Requiremet	Increase/(Decrease) in Revenue Requiremet
Newfoundland Power	(40,281)	(42,872)
Island Industrial	11,016	11,758
Labrador Industrial	28	-
Labrador Interconnected	29,238	31,114

Changes in specifically assigned charges are detailed by Test Year in Table 2.

Table 2 – Specifically Assigned Charges Impact

Particulars ($)	2018 Test Year	2019 Test Year
	Increase/(Decrease) in Specifically Assigned	Increase/(Decrease) in Specifically Assigned
Specifically Assigned Charges	122,150	123,041

Should you have any questions, please do not hesitate to contact the undersigned.

Yours truly,
NEWFOUNDLAND AND LABRADOR HYDRO

Tracey Pennell

Tracey L. Pennell
Senior Counsel, Regulatory

TLP/bs

cc: Gerard Hayes - Newfoundland Power
Paul Coxworthy - Stewart McKelvey Stirling Scales
Denis J. Fleming - Cox & Palmer
Dennis Browne, Q.C. - Consumer Advocate
Dean Porter - Poole Althouse

ecc: Van Alexopoulos - Iron Ore Company
Senwung Luk - Labrador Interconnected Group
Benoît Pepin - Rio Tinto

Revision 4 – November 27, 2017

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Volume 3	Exhibit 17	Pages UT-4, IND-1, 2 and 4, DSL-G 1 to 4, LAB-1 to 5

[1] Will print the whole exhibit as the insertion moved text on majority of pages.

2017 General Rate Application

Volume I

July 28, 2017
Revised – September 15, 2017
Revised – October 16, 2017
Revised – October 27, 2017
Revised – November 27, 2017

newfoundland labrador hydro

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Application

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

AND IN THE MATTER OF a General Rate Application (the Application) by Newfoundland and Labrador Hydro to establish customer electricity rates for 2018 and 2019.

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

The General Rate 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, 2007,* is a public utility within the meaning of the *Act*, and is subject to the provisions of the *Electrical Power Control Act, 1994*.

2. Under the Act, the Board has the general supervision of public utilities and requires that a public utility submit for the approval of the Board the rates, tolls and charges for the service provided by the public utility and the rules and regulations which relate to that service.

3. In Order No. P.U. 49(2016), the Board ordered, amongst other things, that Hydro file its next general rate application no later than March 31, 2017, with a 2018 test year. On February 20, 2017, Hydro filed an application requesting approval to file its next general

rate application on or before July 31, 2017, reflecting 2018 and 2019 test years. In Order No. P.U. 8(2017), the Board ordered Hydro to file its next general rate application by July 31, 2017.

4. In Order No. P.U. 49(2016), the Board ordered, amongst other things, that Hydro file:

(a) By January 13, 2017, a report on its Account Management Framework. This report was filed with the Board on January 13, 2017;

(b) By March 31, 2017, a proposal in relation to annual reporting of intercompany activity, starting in 2017. Hydro's proposal was filed on March 30, 2017. By letter dated June 20, 2017, the Board advised that Hydro's proposal to include the Inter-Affiliate Transactions Report as part of its Quarterly Regulatory Report, starting with the second quarter report of 2017, was accepted;

(c) No later than June 30, 2017, a proposal in relation to an adjustment mechanism for its target return on equity. Hydro filed a report with the Board setting out its proposal on this issue on June 30, 2017. By letter dated July 14, 2017, the Board advised that Hydro's proposal would be considered as part of Hydro's next general rate application. Hydro's report outlining its proposal on an adjustment mechanism for its target return on equity is attached as Exhibit 12 to this Application;

(d) With its next general rate application, a report in relation to its Customer Service Strategic Roadmap. This report is attached as Exhibit 3 to this Application; and

(e) With its next general rate application, a report in relation to the identification of the rural subsidy on customer bills. This report is attached as Exhibit 4 to this Application.

5. In Order No. P.U. 49(2016), the Board accepted the Settlement Agreement and the Supplemental Settlement Agreement (together the Settlement Agreements) that were jointly proposed to the Board by Hydro and the Intervenors. In the Settlement Agreements, the parties agreed that in light of the material change in the forecast supply cost mix with the commissioning of the Muskrat Falls Project, Hydro would file a Cost of Service Methodology Review Report with the Board by March 31, 2016, and would also conduct a comprehensive Cost of Service Methodology Review Hearing in 2016. Hydro filed the required report on March 31, 2016. On July 28, 2016, Hydro proposed to delay the cost of service review until 2018 in light of the delay in the Muskrat Falls Project. By letter dated August 9, 2016, the Board agreed to delay the cost of service review but indicated that there are cost of service issues that need to be addressed as part of Hydro's next general rate application, prior to the inclusion of Muskrat Falls Project costs in Hydro's cost of service, including issues related to the methodology for calculating specifically assigned charges. The Board also directed Hydro to advise of its plan for the full cost of service methodology review to reflect the inclusion of Muskrat Falls Project costs in Hydro's cost of service in its next general rate application. Hydro's plan is included in Chapter 5 of the evidence to this Application.

6. Under the authority of the *Electrical Power Control Act, 1994*, in Order in Council OC2009-063, the Lieutenant Governor in Council directed: that the Board approve Hydro's return on rate base, calculated using the rate of return on equity last approved for Newfoundland Power Inc. (Newfoundland Power) in a general rate application or through Newfoundland Power's Automatic Adjustment formula; that Hydro would earn a return on equity on its entire rate base including amounts related to rural assets; and that Hydro would be permitted to have the proportion of equity in its capital structure up to a maximum of the same approved for Newfoundland Power.

7. In Order No. P.U. 18(2016), the Board approved, for ratemaking purposes, a rate of return on equity of 8.5% for Newfoundland Power and a common equity component in its capital structure not to exceed 45%.

B. Hydro's Proposals:

8. Hydro makes this Application under the *Electrical Power Control Act, 1994* and under the *Act*, and specifically under Sections 58, 64, 70, 71, 75, 76, 78 and 80 of the Act, and requests:

Revenue Requirement

(1) a) that Hydro's proposal to have its 2018 and 2019 Test Year revenue requirements, and resulting rates, reflect the costs of the continued supply of power to the Island Interconnected System from existing Island generation as

described in Chapter 1 and Chapter 5 of the evidence filed in support of this Application, be approved; and

b) that Hydro's proposal to establish a deferral account, the Off-Island Purchases Deferral Account, to include any difference between the: i) actual costs attributable to off-island power purchases including the cost of delivery, and ii) the costs that would have been incurred if that same amount of energy had been supplied from the Holyrood Thermal Generating Station based on the approved Test Years' unit cost of No. 6. Fuel, as described in Chapter 1 and Chapter 5 of the evidence filed in support of this Application, be approved;

(2) that for the purposes of calculating Hydro's 2018 Test Year:

a) a 2018 Test Year revenue requirement of $673,056,000 be approved;

b) a 2018 forecast average rate base of $2,263,109,000 be approved; and

c) a rate of return on rate base of 5.73% in a range of 5.53% to 5.93% be approved;

(3) that for the purposes of calculating Hydro's 2019 Test Year:

a) a 2019 Test Year revenue requirement of $ $692,766,000 be approved;

b) a 2019 forecast average rate base of $2,364,465,000 be approved; and

c) a rate of return on rate base of 5.68% in a range of 5.48% to 5.88% be approved;

(4) a) that Hydro's forecast capital structure for 2018, as set out in Chapter 4 of the evidence in support of this Application, with a weighted average cost of capital of 5.73%, be approved; and

b) that Hydro's forecast capital structure for 2019, as set out in Chapter 4 of the evidence in support of this Application, with a weighted average cost of capital of 5.68%, be approved;

(5) that pursuant to Order in Council OC2009-063, for purpose of calculating Hydro's return on rate base for 2018 and 2019, the return on equity last approved by Order No. P.U. 18(2016), as a result of Newfoundland Power's general rate application, of 8.5 %, be approved;

(6) that the Holyrood conversion rate of 616 kWh per barrel for the 2018 Test Year and the 2019 Test Year, be approved;

Regulatory Accounting

(7) that Hydro's continued use of the working capital methodology, as set out in Chapter 4 and Exhibit 9 of the evidence in support of this Application, be approved;

(8) that Hydro's proposed average rate base methodology, as set out in Chapter 4 and Exhibit 10 of the evidence in support of this Application, be approved;

(9) that Hydro's proposed depreciation rates and methodology, as set out in Chapter 4 and Exhibit 11 of the evidence in support of this Application, be approved;

(10) that Hydro's proposal in relation to an automatic adjustment mechanism for its target return on equity to reflect any changes to Newfoundland Powers' approved target return on equity for rate setting, as set out in Chapter 4 and Exhibit 12 of the evidence in support of this Application, be approved;

(11) that Hydro's proposal to amortize and recover general rate hearing costs in the amount of $1.2 million, at a rate of $0.4 million per year for three years commencing in 2018, as set out in Chapter 4 of the evidence in support of this Application, be approved;

(12) that Hydro's proposal to amortize and recover cost of service hearing costs in the amount of $0.5 million, at a rate of $0.17 million per year for three years commencing in 2018, as set out in Chapter 4 of the evidence in support of this Application, be approved;

(13) that Hydro's proposal to recover its 2018 revenue deficiency over a twenty month period commencing January 1, 2019, as set out in Chapter 4 and Chapter 5 of the evidence in support of this Application, be approved;

(14) that Hydro's proposal to include its 2018 revenue deficiency in rate base, as set out in Chapter 4 of the evidence in support of this Application, be approved;

(15) that Hydro's proposal to include an allowance of $2.1 million per year from January 1, 2018 to March 31, 2021, in relation to inventory at the Holyrood Thermal Generating Station and create an inventory allowance, as set out in Chapter 4 of the evidence in support of this Application, be approved;

(16) that Hydro's excess earnings account definition, as provided in Chapter 4 of the evidence in support of this Application, be approved;

Cost of Service Methodology

(17) that the generation credit service agreement between Hydro and Corner Brook Pulp and Paper, which was approved on a pilot basis by the Board in Order No. P.U. 4(2012), as set out in Chapter 5 and Exhibit 13 to the evidence in support of this Application, be discontinued;

(18) that Hydro's proposal to allocate operating and maintenance expenses for specifically assigned assets by customer be based on the determination of test year transmission asset values via Handy-Whitman indexes, as set out in Chapter 5 and Exhibit 13 to the evidence in support of this Application, be approved;

(19) that wind energy purchases be classified as 100% energy-related, as set out in Chapter 5 of the evidence in support of this Application, be approved;

2018 Interim Rates and Interim Rate Design

(20) that, effective January 1, 2018, rates for 2018 be approved on an interim basis for all of Hydro's customers, as set out in Chapter 5 and Exhibit 16 of the evidence in support of this Application;

(21) that Hydro's proposed revised 2018 rates for Newfoundland Power, specifically:

a) a Demand rate of $5.00 per kW per month; and

b) a First Block Energy rate of 3.443 cents per kWh;

as set out in Chapter 5 and Exhibit 16 to the evidence in support of this Application, be approved on an interim basis effective January 1, 2018;

(22) that Hydro's proposed revised 2018 rates for the Island Industrial Customers, specifically:

a) a Demand rate of $9.93 per kW per month; and

b) an Energy rate rider of 0.100cents per kWh; and

c) annual Specifically Assigned charges as follows:

i.	Corner Brook Pulp and Paper Limited	$732,673
ii.	North Atlantic Refining Limited	$183,050
iii.	Teck Resources Limited	$51,173
iv.	Vale Newfoundland and Labrador Inc.	$165,774

as set out in Chapter 5 and Exhibit 16 to the evidence in support of this Application, be approved on an interim basis effective January 1, 2018;

(23) that Hydro's proposed demand rate and revised rate design for Labrador Industrial Transmission rates, as set out in Chapter 5 and Exhibit 16 to this evidence in support of this Application, be approved on an interim basis effective January 1, 2018;

(24) that Hydro's proposed rules and regulations governing service, as set out in Chapter 5 and Exhibit 16 to the evidence in support of this Application, be approved on an interim basis effective January 1, 2018;

<u>2019 General Rate Proposals</u>

(25) that, effective January 1, 2019, rates for 2019 for all of Hydro's customers, as set out in Chapter 5 and Exhibit 17 of the evidence in support of this Application, be approved on a final basis;

(26) that Hydro's 2019 proposed rates for Newfoundland Power, specifically:

a) a Demand rate of $5.25 per kW of billing demand per month;

b) an increase in the First Block Energy from 250 GWh to 290 GWh per month at a rate of 3.821 cents per kWh;

c) an Energy rate of 14.141 cents per kWh for all excess kWhs; and

d) a Firming-up Charge of 2.882 cents,

as set out in Chapter 5 and Exhibit 17 to the evidence in support of this Application, be approved on a final basis;

(27) that, effective January 1, 2019, the decrease in Newfoundland Power's Generation Credit from 119,329 kW to 118,054 kW, as set out in Chapter 5 and Exhibit 17 to the evidence in support of this Application, be approved on a final basis;

(28) that, effective January 1, 2019, the RSP fuel rider applicable to Newfoundland Power, as approved in P.U. 22(2017), be discontinued;

(29) that for Newfoundland Power, an additional monthly charge of $902,506 for the period January 1, 2019 to August 31, 2020, to recover the forecast 2018 revenue deficiency, as set out in Chapter 5 and Exhibit 17 to the evidence in support of this Application, be approved on a final basis;

(30) that Hydro's proposed 2019 rates for the Island Industrial Customers, specifically:

a) an Demand rate of $11.12 per kW per month;

b) an Energy rate of 4.792 cents per kWh; and

c) annual Specifically Assigned charges as follows:

i.	Corner Brook Pulp and Paper Limited	$861,911
ii.	North Atlantic Refining Limited	$193,496
iii.	Teck Resources Limited	$51,566
iv.	Vale Newfoundland and Labrador Inc.	$170,233

as set out in Chapter 5 and Exhibit 17 to the evidence in support of this Application, be approved on an final basis effective January 1, 2019;

(31) that for the Island Industrial Customers, a Demand Deficiency rate of $0.50 per kW per month and an Energy Deficiency rate of 0.025 cents per kWh for the period January 1, 2019 to August 31, 2020, to recover the forecast 2018 revenue deficiency, as set out in Chapter 5 and Exhibit 17 to the evidence in support of this Application, be approved on a final basis;

(32) that, effective January 1, 2019, the removal of the RSP fuel rider applicable to Island Industrial Customers approved in P.U. 22(2017), as set out in Chapter 5 and Exhibit 17 to the evidence in support of this Application, be approved on a final basis;

(33) that, effective January 1, 2019, a loss factor of 3.34% be approved for use in calculation of the non-firm Island Industrial energy rate, as set out in Chapter 5

and Exhibit 17 to the evidence in support of this Application, be approved on a final basis;

(34) that Hydro's proposed demand rate and revised rate design for Labrador Industrial Transmission, as set out in Chapter 5 and Exhibit 17 to this evidence in support of this Application, be approved on a final basis effective January 1, 2019;

(35) that the proposed rates, tolls and charges as set out in Chapter 5 and Exhibit 17 to this evidence in support of this Application, be approved on a final basis;

(36) that the proposed rules and regulations governing service as set out in Chapter 5 and Exhibit 17 to this evidence in support of this Application, be approved on a final basis; and

(37) that upon hearing this Application, the Board grant such alternative, additional or further relief as the Board shall consider fit and proper in the circumstances.

C. Reasons for Approval

9. Approval by the Board of the proposals in this Application will permit cost recovery through customer rates as provided for, and intended by, the *Act*, the *Electrical Power Control Act, 1994* and the Orders of the Board set out in the Application.

D. Communications:

10. Communication with respect to this Application should be forwarded to the attention of Tracey L. Pennell and J. Alex Templeton, Counsel to Newfoundland and Labrador Hydro.

DATED AT St. John's in the Province of Newfoundland and Labrador this 28th day of July 2017.

NEWFOUNDLAND AND LABRADOR HYDRO

Tracey Penell

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

AND IN THE MATTER OF a General Rate Application (the Application) by Newfoundland and Labrador Hydro to establish customer electricity rates for 2018 and 2019.

AFFIDAVIT

I, James R. Haynes, Professional Engineer, of St. John's in the Province of Newfoundland and Labrador, make oath and say as follows:

1. I am President, 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 28th day of July, 2017,)
before me:)

Tracey Pennell

Barrister – Newfoundland and Labrador

James R. Haynes

Chapter 1 - Overview

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Chapter 1 Corporate Overview

1.1 Introduction

Newfoundland and Labrador Hydro (Hydro) files this 2017 General Rate Application (the Application or GRA) with the Board of Commissioners of Public Utilities (the Board) pursuant to the *Public Utilities Act*[1] to request rates, amongst other proposals, for a two year test-period in 2018 and 2019, as summarized in Section 1.1.3.

The proposed general rates and revenue requirements in this Application reflect Hydro's efforts to manage and control its costs while delivering safe, reliable service to its customers.

The Evidence to this Application is structured as follows:

- Chapter 1: Corporate Overview. This Chapter provides a high level overview of the context for this Application and the key components of Hydro's revenue requirements.
- Chapter 2: Customers. This Chapter provides information on Hydro's approach to serving customers throughout Newfoundland and Labrador, measuring customer satisfaction, initiatives Hydro has implemented to ensure a balance between customer service and costs, and Hydro's commitment to conservation and demand management.
- Chapter 3: Operations. This Chapter outlines Hydro's revised organizational structure, operational processes, system performance, forecast customer load requirements, forecast operating costs, and a discussion on Hydro's preparation for interconnection with the North American grid.
- Chapter 4: Finance. This Chapter provides Hydro's test year revenue requirements, average rate base, return on rate base, and financial proposals relating to depreciation rates and methodology, working capital, average rate base methodology, automatic return on equity adjustment, and proposed regulatory deferrals.

[1] *Public Utilities Act*, RSNL 1990, c.P-47; http://www.assembly.nl.ca/Legislation/sr/statutes/p47.htm

- Chapter 5: Rates and Regulations. This Chapter provides Hydro's proposed Cost of Service methodology for the current application and the recovery of rates proposals to recover revenue requirements for the 2018 and 2019 Test Years.

The Evidence is also comprised of a number of Exhibits, which provide further information on the evidence presented in the above noted chapters, as well as expert evidence, cost of service studies, and Hydro's proposed schedules of rates, rules, and regulations.

1.1.1 The Applicant – Newfoundland and Labrador Hydro

Hydro is a Crown corporation with a mandate to:

- develop and purchase power and energy on an economic and efficient basis;
- engage in the development, generation, production, transmission, distribution, delivery, supply, sale, purchase and use of power from water, steam, gas, coal, oil, wind, hydrogen and other products; and
- supply power, at rates consistent with sound financial administration, for domestic, commercial, industrial, or other uses in the province and subject to the prior approval of the Lieutenant-Governor in Council, outside of the province.[2]

As the main generator and transmitter of electricity in the Province of Newfoundland and Labrador, Hydro is focused on providing safe, reliable, least-cost electricity to meet current energy demands and future growth of its customers.[3] Hydro's activities can be grouped as follows:

- Electricity generation – Hydro has an installed generating capacity of 1,763 megawatts (MW) which includes nine hydroelectric generating stations, one oil-fired plant, four gas turbines, and 25 diesel plants, including 21 isolated diesel systems. Hydro is also responsible for forecasting electricity requirements in the province and advancing options to ensure adequate supply to reliably meet electricity demand.

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[2] *Hydro Corporation Act*, *2007*, SNL 2007, c.H-17; http://www.assembly.nl.ca/legislation/sr/statutes/h17.htm
[3] A description of the electrical system is provided in Exhibit 1.

- Transmission and Distribution – Hydro operates and maintains over 3,700 kilometres of transmission lines[4] and more than 50 high voltage terminal stations which connect to the generation and delivery points for Newfoundland Power Inc. (Newfoundland Power), Industrial customers, and Hydro's rural distribution systems. Hydro also operates and maintains approximately 2,700 kilometres of distribution lines.[5]
- System Operations – Hydro operates and provides oversight of the electricity system to reliably meet the changing requirements of electricity customers by utilizing the combination of available generation and power delivery resources to provide service safely, reliably, and cost effectively.
- Customer Service – Customer service activities address the requirements of Newfoundland Power and its customers, industrial customers, and approximately 38,600 direct residential and commercial customers in rural Newfoundland and Labrador.

1.1.2 Purpose of Application

The purpose of this Application is to update the rates to be charged for the supply of power and energy by Hydro to allow recovery of costs associated with business operations and allow an opportunity for a reasonable return. This includes updating rates for the supply of electricity to its Rural and Industrial customers and to Newfoundland Power, as well as to update the Rules and Regulations applicable to the supply of electricity to Hydro's customers.

Hydro's current base rates were last set effective July 1, 2017, based on a 2015 Test Year. Since its last general rate application, Hydro has:

- restructured its operations to support the delivery of safe, reliable service to its customers;
- prioritized capital spending to maintain system reliability and meet customer needs;

[4] Transmission lines are defined as those operating on systems of 46kV and above.
[5] Distribution lines are defined as those operating on systems less than 46kV.

- implemented operational changes to drive a reliability and customer focused culture; and
- instituted a productivity allowance to manage operating costs to help offset other cost pressures.

Hydro's efforts have resulted in improving levels of reliability to end consumers since 2013 and 2014. Customer satisfaction has also improved since 2014.

The key factors underpinning the requests made in this Application are:

- In Order No. P.U. 49(2016) the Board directed Hydro to file its next general rate application by March 31, 2017. In Order No. P.U. 8(2017), the Board directed Hydro to file its next general rate application to July 31, 2017.
- As part of its commitment to provide reliable service to its customers, Hydro is investing in its aging asset base and in the construction of new assets. This includes the construction of a third transmission line (TL267) from Bay d'Espoir to Western Avalon with a total capital expenditure of approximately $291 million. TL267 will have a positive impact on system reliability and will help alleviate system constraints relating to power flow to the Avalon Peninsula resulting from an increase in customer demand. In 2017, Hydro is forecast to invest approximately $370 million in its capital assets. In 2018 and 2019, Hydro is forecast to spend approximately $206 million and $147 million, respectively.
- To ensure reliable service for its customers, Hydro's costs have increased due to an increase in capital investment and fuel costs, and a moderate increase in operating costs, partially offset by a lower weighted average cost of capital.
- It is well known that the impact of the Muskrat Falls Project on customer rates will be significant. Hydro has been working with its parent company, Nalcor Energy (Nalcor), and the Government of Newfoundland and Labrador, to determine potential options to help mitigate and manage these cost increases for customers. It is anticipated that the Labrador-Island Link and the Maritime Link will be available in 2018 and 2019 to provide

off-island purchases to reduce the generation required from the Holyrood Thermal Generating Station (Holyrood). This presents an opportunity to reduce the use of costly Holyrood generation by using lower cost off-island purchases in 2018, 2019, and 2020. Hydro's 2018 and 2019 Test Year revenue requirements, as submitted, reflect the continued use of Holyrood fuel with no access to off-island purchases. Hydro is proposing that any costs or savings associated with the use of the Labrador-Island Link and the Maritime Link prior to the full commissioning of the Muskrat Falls Project be set aside in a deferral account. This proposal will set aside any potential savings from off-island purchases to mitigate future rate increases after the full commissioning of the Muskrat Falls Project.

1.1.3 Application Proposals

The major components of Hydro's requests are summarized below.

Basis of 2018 and 2019 Revenue Requirement

Hydro is proposing that its 2018 and 2019 Test Year revenue requirements, and resulting rates, reflect the continued supply of power to the Island Interconnected System from existing Island generation. Hydro is proposing to establish a deferral account, the Off-Island Purchases Deferral Account, to include any difference between: (i) the actual costs attributable to off-island power purchases including the cost of delivery, and (ii) the costs that would have been incurred if that same amount of energy had been supplied from the Holyrood Thermal Generating Station based on the approved Test Years' unit cost of No. 6 fuel.[6]

Hydro is proposing final rates based on a 2019 Test Year. The 2018 Test Year revenue requirement will be used to determine revenue deficiency due to delayed rate implementation, anticipated to be January 1, 2019.

[6] Hydro will file supplemental evidence in the Fall of 2017 to provide more detail on the proposed Off-Island Purchases Deferral Account which must align with the operation of the Rate Stabilization Plan (RSP).

Customer Impacts – Rates

Hydro anticipates that final rates resulting from this Application will not be in effect until the fourth quarter of 2018 or the beginning of 2019. Rate implementation in 2019 will result in a revenue deficiency of approximately $70.3 million for 2018. Hydro is therefore proposing that interim customer rates be implemented effective January 1, 2018, with the proposed increase providing recovery of approximately 70% of the increased revenue requirement for 2018.

Hydro's proposals in this Application result in the following interim customer rates to be effective January 1, 2018, relative to July 1, 2017 rates:

- a rate increase of 9.8% to Newfoundland Power which results in an approximate 6.6% increase to Island Interconnected end customers and customer rates on the L'Anse au Loup System;
- an average increase in rates of 6.3% to Hydro's Island Industrial Customers;
- an average increase of 4.4% to customers on the Labrador Interconnected System; and
- an average 6.6% increase in rates to customers on the isolated diesel systems.

Hydro's proposals in this Application result in the following final customer rates increases to be effective January 1, 2019, relative to January 1, 2018 interim rates:

- a rate increase of 9.4% to Newfoundland Power which results in an approximate 6.4% increase to Island Interconnected end customer and customer rates on the L'Anse au Loup System;
- an average increase in rates of 7.1% to Hydro's Island Industrial Customers;
- an average increase of 8.2% to customers on the Labrador Interconnected System; and
- an average 6.4% increase in rates to customers on the isolated diesel systems.

Table 1-1 provides a summary of the average customer rate impacts by class.

Table 1-1 Proposed Average Interim and Final Rate Changes by Customer Class (%)[7]

Customer Class	Interim 2018 TY Increase Relative to July 1, 2017 Rates	2019 TY Increase Relative to January 1, 2018 Interim Rates
Newfoundland Power – Wholesale	9.8	9.4
Newfoundland Power – Retail	6.6	6.4
Island Industrial	6.3	7.1
Labrador Interconnected	4.4	8.2
Labrador Industrial Transmission	15.1	28.3[8]
Hydro Rural Government Diesel	8.9	13.8
Hydro Rural Other[9]	6.6	6.4

Other Proposals

Hydro is also seeking approval of the following:

- the working capital methodology recommended in the Working Capital Methodology Review (see Chapter 4 and Exhibit 9);
- the continued use of its existing average rate base methodology (see Chapter 4 and Exhibit 10);
- the depreciation rates and methodologies recommended in the 2016 Depreciation Study (see Chapter 4 and Exhibit 11);
- Hydro's proposal in relation to an automatic adjustment mechanism for its return on equity (see Chapter 4 and Exhibit 12);
- the deferral and amortization of GRA hearing costs and cost of service hearing costs (see Chapter 4);
- the deferral and recovery of the 2018 revenue deficiency over a twenty-month period (see Chapter 4 and Chapter 5);
- a revised excess earnings account definition (see Chapter 4);

[7] The percentage increases were calculated assuming the Rate Stabilization Plan (RSP) Current Plan riders under existing and proposed rates.
[8] The percentage increase in the Labrador Industrial Transmission rate does not provide the total customer billing impact as the percentage is calculated based on the projected change in transmission demand charges but does not include the non-regulated portion of the bill that recovers generation costs.
[9] Projected rate change based on Newfoundland Power retail rate change.

- Cost of Service Methodology proposals related to i) the method for allocating operating and maintenance costs to specifically assigned assets, ii) the Rural Deficit allocation methodology, and iii) the classification of wind generation purchases (See Chapter 5 and Exhibit 13);
- interim rules and regulations for service to Hydro's Rural Customers on an interim basis, effective January 1, 2018, and on a final basis effective January 1, 2019 (see Chapter 5 and Exhibits 16 and 17); and
- a revised transmission demand rate for Labrador Industrial Customers to promote the efficient use of customers' demand requirements (see Chapter 5).

1.2 Managing Customer Electricity Rates in Transition to Interconnection with the North American Grid

1.2.1 Background

Hydro's parent company, Nalcor, is currently building the Muskrat Falls Project on the lower Churchill River in Labrador. The project includes construction of an 824 megawatt (MW) hydroelectric dam on the lower Churchill River, and more than 1,500 km of associated transmission lines that will deliver electricity to homes and businesses in Newfoundland and Labrador. The project is comprised of three main components:

- The Muskrat Falls Hydroelectric Generating Facility (Muskrat Falls Plant),
- The Labrador-Island Link (the LIL) transmission assets which will carry electricity from the Muskrat Falls Plant to the island of Newfoundland, and
- The Labrador Transmission Assets (the LTA), which are comprised of two transmission lines to transmit power between the Muskrat Falls Plant and the existing 5,428 MW hydroelectric facility in Churchill Falls.

In conjunction with the Muskrat Falls Project, Emera Inc. (Emera) is building the Maritime Link (the ML) which will connect the island of Newfoundland and Nova Scotia.

1.2.2 Access to Off-Island Purchases

In June 2017, Nalcor announced that the LIL and the LTA are scheduled to enter service in mid-2018, ahead of the associated Muskrat Falls Plant commissioning date in 2020. The Maritime Link is scheduled to enter service at the end of 2017. The availability of the LIL, LTA, and ML transmission lines expected in 2018 will provide Hydro with off-island supply options for the Island electricity system from 2018 to 2020 while the construction of the Muskrat Falls Plant continues.

With the availability of the LIL and LTA prior to full commissioning of the Muskrat Falls Project, there is a significant opportunity to reduce Holyrood generation by using off-island purchases in 2018, 2019, and 2020. For 2018 and 2019, the availability of off-island purchases will primarily be from Recapture Energy.[10] In 2020, commissioning period energy is anticipated to be available from the Muskrat Falls Plant. The Maritime Link will also be available and there may be opportunities via the ML to purchase short term supplies to further reduce fuel use. This opportunity will be managed by Nalcor Energy Marketing, on behalf of Hydro, who has met with Nova Scotia Power and other market participants to determine if, and how much, non-firm "economy" energy is available.

For the period from 2018 until full-commissioning of the Muskrat Falls Project, the use of off-island purchases could provide a reduction in the range of 1.3 to 2.3 TWh in Holyrood generation and avoid the purchase of between 2.1 million and 3.6 million barrels of oil. There is

[10] Under the terms of the Power Purchase Agreement between Hydro and Churchill Falls (Labrador) Corporation (CF(L)Co) (the NLH-CF(L)Co PPA), Hydro is able to, and does, purchase approximately 300 MW of Recapture Energy from CF(L)Co at a cost of 0.2¢ per kWh for use outside of the Province of Quebec. Hydro currently uses a portion of the Recapture Energy to supply its customers in Labrador (the Labrador Load) with the remainder of the Recapture Energy sold to Nalcor Energy Marketing (NEM) at a cost of 0.2 cents (¢) per kWh for resale in external markets. Hydro does not profit from the arrangement with NEM, which is consistent with the long-standing treatment of Hydro's previous arrangement with Hydro Quebec whereby external sales from Recapture Energy were segregated from regulated earnings and essentially treated as a direct dividend to the Province. Under the present arrangement, NEM retains any profit obtained from selling the excess Recapture Energy to market which flow up to Nalcor Energy as dividends.

also the added environmental benefit, as this would result in an estimated reduction in GHG emissions of between 1.0 and 1.8 million tonnes of CO_2 at Holyrood.

1.2.3 Obligation to Provide Open Access

As a result of the Muskrat Falls Project transmission assets and the ML providing service in advance of the full commissioning of the Muskrat Falls Project, Hydro and Nalcor will be expected to provide open access to its transmission facilities. The provision of open access requires the implementation of a transmission tariff, which conforms to reciprocity standards.

Under an open access regime, operating and maintenance costs associated with transmission facilities are recovered through a published transmission tariff. Reciprocity standards will require that Hydro also pay the published transmission tariff that is chargeable to outside third parties that want to flow energy on the provincial transmission grid. While Order in Council OC2013-343 directs that costs associated with the Muskrat Falls Project be recovered from Island Interconnected rates, it prohibits the recovery of those costs until the project is commissioned or near commissioning and Hydro is receiving services.

1.2.4 Opportunity

Hydro is proposing that the costs to use the Muskrat Falls Project transmission assets be recognized and paid for from the savings from off-island purchases.

Hydro is also proposing to establish a deferral account which will include both the fuel savings from off-island purchases and the actual costs attributable to off-island power purchases, including transmission costs for delivery. The deferral account will permit the savings from off-island purchases to offset the transmission costs to be incurred by Hydro. Any additional savings will be set aside for the benefit of customers.

Future customers will be required to provide recovery of the costs of the Muskrat Falls Project. Hydro considers it reasonable that future customers receive the benefit from any savings that can be achieved through use of the Muskrat Falls Project transmission assets. Setting customer rates for 2018 and 2019 such that the potential net savings derived from the use of the transmission assets are deferred to mitigate the full Muskrat Falls Project costs is consistent with the principle of intergenerational equity.

Nalcor's June 23, 2017 project update stated that average island residential electricity rates are expected to increase to 22.89 cents (¢) (plus HST) per kilowatt hour (kWh) in 2021 as a result of the Muskrat Falls Project. The present average rate for these customers is 11.7 ¢ per kWh (plus HST), a gap of 11.19 ¢ per kWh.

Hydro's proposal to have its 2018 and 2019 Test Year revenue requirements, and resulting rates, not consider any off-island power supplied to the Island through the operation of the Labrador-Island Link or the Maritime Link, will permit customer rates to gradually increase leading up to inclusion of the Muskrat Falls Project costs in rates. While Hydro is proposing rate increases of 6.6% in 2018 and 6.4% in 2019 (excluding the impacts of Rate Stabilization Plan adjustments), the projected rate increases are primarily related to the recovery of costs resulting from capital additions on the Island Interconnected System from 2015 to 2019. Reflecting the forecast savings from off-island purchases to customers in the 2018 and 2019 Test Year revenue requirements is anticipated to keep rates flat, or potentially reduce rates slightly. Decreasing customer rates prior to completion of the Muskrat Falls Project will make the gap worsen. Implementation of Hydro's proposal will increase the average Domestic customer rate from 11.7 ¢ per kWh (before HST) to approximately 13.3 ¢ per kWh (before HST) in 2019.

The actual savings will vary depending on: (i) the availability date of the LIL and LTA; (ii) Holyrood fuel price; (iii) energy available for import from other jurisdictions; and (iv) the costs of operating and maintaining the LIL and LTA.

1.2.5 Regulatory Practice

Hydro's proposal is not without regulatory precedent.

In Order 73/15, Manitoba's Public Utilities Board approved an interim rate increase for Manitoba Hydro of 3.95%. The revenues from 2.15% of that rate increase are to be placed in a deferral account to mitigate expected rate increases from when the Bipole Transmission Reliability Project (Bipole III) comes into service in 2018/19. In Order 73/15, the Manitoba regulator stated that, "Because very significant rate increases will be needed at that time, the Board sees a compelling policy reason to gradually increase rates to avoid rate shock for consumers three years from now."[11] The funds set aside in the Board-ordered deferral account will be used to smooth the significant rate increases that may otherwise be required when the Bipole III is completed, helping to mitigate the resulting rate shock.[12]

Hydro's proposal is consistent with the regulatory principle of rate stability and will assist in mitigating the anticipated Muskrat Falls Project rate shock.

1.3 Corporate Organization

Since its last general rate application, Hydro has undergone significant organizational changes to create a company with operational independence from its parent company, Nalcor. Hydro has aligned its structure so that it can focus on its business of providing electricity to customers, separate from Nalcor's unregulated business lines, and to ready itself for interconnection with the North American grid. The result of these organizational changes is a Hydro team with a focus on safety, customer reliability and cost-effectiveness.

[11] Manitoba Public Utilities Board, Order 73/15 at page 3. Manitoba Hydro's regulator recently approved an additional 2.15% rate increase to build a deferral account to mitigate rate increases when the Bipole III project comes into service in 2018/2019.

[12] The Manitoba Public Utilities Board in Order 59/16 approved an additional 3.36% interim rate increase effective August 1, 2016, with all additional revenue generated from this interim increase to flow into the previously established Bipole III Deferral Account.

Key aspects of the new organizational structure include:[13]

- a dedicated and separate executive team that report directly to, and are accountable to, the President of Hydro;
- a Production division, encompassing Hydro Generation, the Holyrood Thermal Generating Station, Hydro's fleet of gas turbines and diesels, and Exploits Generation, as well as Resource and Production Planning;[14]
- a Transmission and Distribution division that will include the Newfoundland and Labrador System Operator (NLSO), Transmission Planning, Rural Planning, and Transmission and Rural Operations;
- An Engineering Services division focused on Hydro's engineering activities, project execution, asset management, and operational and information technology;
- a Corporate Services and Regulatory Affairs division which includes Customer Service, Energy Efficiency, as well as Human Resources, Safety and Health, Environmental Services, Communications and Regulatory Affairs;
- a Corporate Secretary and General Counsel division responsible for providing legal advice to Hydro and corporate secretarial services; and
- a Financial Services division, which includes Controller, Treasury, Risk and Controls, Commercial Management , Internal Audit, and Supply Chain administration.[15]

Figure 1-1 presents the executive structure for Hydro.[16]

[13] The new organizational structure is discussed in detail in Exhibit 2.
[14] Exploits Generation is operated and maintained by Hydro under agreement with the Province.
[15] While the Internal Audit department reports functionally to the Board of Directors, from a Human Resources perspective employees report to the Vice President, Financial Services.
[16] Exhibit 2 provides more information on the organizational structure of Hydro.

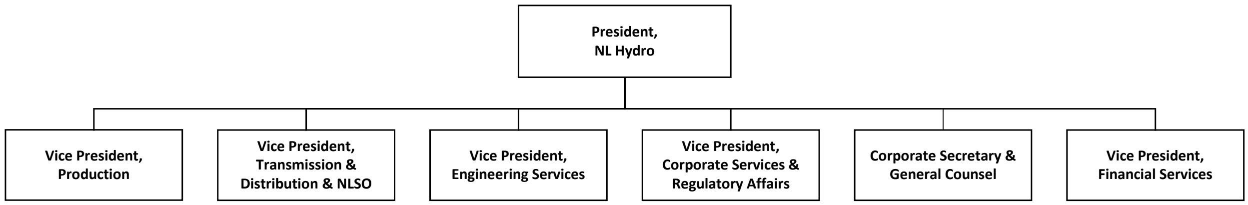

Figure 1-1 Executive Structure

Hydro will continue to outsource limited shared services from Nalcor for certain human resources services, such as payroll and benefits, information services, select safety, health, and environmental services, and limited legal services.[17] Hydro's executive maintains accountability for services provided by Nalcor as an external service provider and affiliate. Hydro will continue to provide Network Services and Supply Chain services to Nalcor.[18] The Company has an obligation to ensure customers pay for only those costs incurred to meet electricity requirements. Hydro recognizes that intercompany transactions must be fully transparent, prudent, and provide demonstrable benefits to the utility and its customers. Hydro is committed to reporting to the Board, on a quarterly basis, on its intercompany activity.[19]

1.4 Customer Service and Satisfaction

Hydro is responsible for ensuring the reliable supply of least cost power to approximately 38,600 direct rural customers across the province. Hydro is currently executing its Customer Service Strategic Roadmap with a focus on improving service to its customers. Hydro now has an Account Management Framework to guide its customer interfaces with key commercial and industrial customers, as well as Newfoundland Power. Hydro's residential customer service satisfaction levels have steadily increased since 2012. In 2016, residential customers in Hydro's

[17] Other areas of shared services include treasury, insurance, and per-use engineering and finance resources.
[18] Network Services is a department within the Information and Operations Technology division of Engineering Services at Hydro that is responsible for tele-protection, telecommunications, remote supervisory control, local and wide area networking as well as telephone and voice services. Information Services is a department within the Nalcor Finance division responsible for all Business Application Services, Collaboration Services, End User Services and Information Technology for all common services across Nalcor companies.
[19] Hydro's proposal in relation to inter-affiliate transaction reporting was filed with the Board on March 30, 2017 and accepted on June 20, 2017.

service areas rated their overall satisfaction with Hydro at 90% customer satisfaction - up from 84% in 2014 and 80% in 2012.

Hydro is focused on open and transparent sharing of information regarding the complex workings of the electricity system with its customers. Hydro recently launched a new mobile and web portal platform in which its customers can easily access their electricity accounts online and subscribe to text and email notifications about power outages (planned and unplanned) in their regions. Hydro also works closely with Newfoundland Power to inform customers when generation reserve levels are lower than target. The Company, along with Newfoundland Power, has developed and implemented three levels of alerts to advise customers on the status of the electrical system so customers can better prepare for any potential impacts. Hydro also advises customers and stakeholders of significant equipment outages through public advisories posted on its website and social media outlets. In addition, Hydro has added educational items to its website to aid the interested customers' understanding of how the overall system works, energy conservation tips, and outage preparation tools.

Other notable customer service initiatives include the implementation of a modern interactive voice response telephone system, after-hours customer support, the use of automated meter reading technology to provide more accurate meter reading, the move to eBilling, and the implementation of new billing and customer service software.

Hydro continues to deliver customer energy conservation programs. This includes the takeCHARGE program offered in conjunction with Newfoundland Power, and customer specific programs such as the Isolated Systems Community Energy Efficiency Program and the Industrial Energy Efficiency Program. These programs are aimed at assisting customers in reducing their electricity usage and promoting energy efficiency.

1.5 Safe and Reliable Operations

Hydro is committed to providing safe, least cost, reliable power to customers by investing appropriately in the electrical system and managing its controllable costs. Hydro is also actively preparing for integration with the North American grid.

Hydro's highest priority is the safety of its employees, contractors, and the general public. Hydro strives to ensure continued improvement of its safety management system, especially in areas that are fundamental to a well-run electrical utility. Hydro continues to focus on its safety programs, including the Safe Workplace Observation Program, the Work Protection Code, Work Methods, the Grounding and Bonding Program, the New and Young Worker Program, and the Contractor Safety Management Program. These, and other safety programs, reduce the potential for incidents that can cause harm to Hydro's employees, contractors, and the public.

Hydro also has Health and Wellness initiatives including wellness clinics, an early and safe return to work program, and an increased emphasis on mental health, all of which focus on improving the well-being of its employees.

1.5.1 Asset Management

Like most other North American utilities, Hydro is managing a base of aging assets. This requires focused and strategic investment to ensure safe and reliable supply of electricity. While Hydro has invested significantly in its assets in recent years, there remains a need for continued investment to ensure reliability of the system is sustained for customers. Hydro's capital plan addresses the need to sustain the existing asset base, strengthen the power grid, respond to customer demand, and improve reliability for customers. Hydro is committed to balancing the provision of least cost and reliable power to its customers by proactively managing its assets and appropriately investing in strategic capital projects. Figure 1-2 shows the age of Hydro's generation and transmission assets as of 2017.

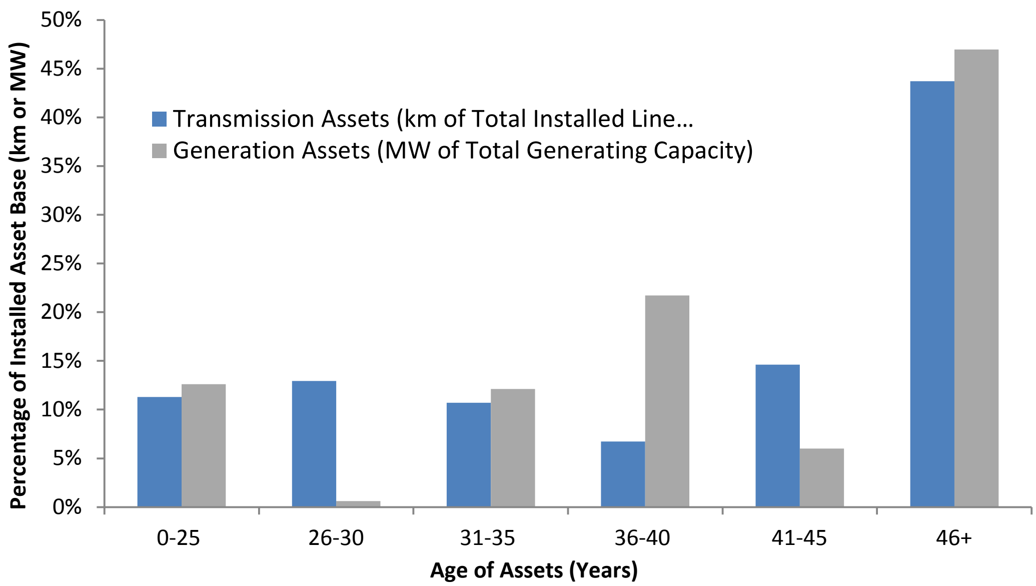

Figure 1-2 Age of Hydro's Generation and Transmission Assets as of 2017

In 2015, Hydro started the first year of a five-year breaker replacement program. In 2016, it started the acceleration of TL267 from Bay d'Espoir to Western Avalon, a key project that will allow Hydro to bring more capacity from its generating assets on the island to customers on the Avalon Peninsula where demand is concentrated. This project is currently scheduled to be in service in late 2017 and will result in added stability of the transmission network and a significant improvement to reliability.[20] The increased availability of existing hydraulic generation capacity will reduce the requirement for Holyrood to support the Avalon Peninsula load, and will, in turn, reduce fuel costs. In 2017, the Company is on track to complete $370 million in capital projects contributing to improved reliability for customers. This includes strengthening and reinforcing the resiliency of the transmission system. Hydro is planning to invest approximately $206 million and $147 million in 2018 and 2019, respectively, to address the need to sustain its existing asset base and grow responsibly and sustainably to meet

[20] A serious incident on June 19, 2017, resulted in the fatality of two contractor employees. An investigation is currently being carried out by Occupational Health and Safety. At the time of filing, all guyed tower activities have been suspended; however, other ground activities and station work are continuing to resume in a phased approach. Hydro is currently assessing the impact the incident will have on the in-service date.

customer demand, while improving reliability and adhering to Hydro's principles of safety and environmental responsibility.

1.5.2 Customer Focused Operations

In 2014, Hydro implemented new load forecasting tools and processes; system, weather and reserve assessments are completed daily; and the stakeholder notification process and inter-utility operations have been enhanced through the development of clear protocols and communication channels. Hydro has also refined its protocols and implemented guidelines for managing the electricity system during adverse events. This includes improved severe weather preparedness protocols and the dispatch of employees and standby generation in advance of events and system peaks.

1.5.3 System Performance

Recognizing that the Company's reliability performance affects more than just its direct customers, in 2016, Hydro introduced a new reliability performance index to measure the reliability of Hydro's system in meeting the demand of all end users (consumers) of electricity in the province, including those not supplied directly by Hydro. Table 1-2 shows the End Consumer System Average Interruption Frequency Index[21] (SAIFI) and System Average Interruption Duration Index[22] (SAIDI) from 2012 to 2016.

[21] System Average Interruption Frequency Index is a reliability key performance indicator, which measures the average cumulative number of sustained interruptions per customer per year.

[22] System Average Interruption Duration Index is a reliability key performance indicator, which measures service continuity in terms of the average cumulative duration of outage hours per customer served during the year.

Table 1-2 End Consumer Performance[23]

	2012	2013[24]	2014[25]	2015	2016
SAIFI	1.25	2.14	5.15	1.31	1.30
SAIDI	1.88	8.61	10.58	2.08	2.42

Since 2014, Hydro's End Consumer performance for SAIFI and SAIDI has improved by approximately 75% and 77%, respectively. Hydro also continues to measure the reliability of its transmission, distribution, and generation assets with a focus on directing both operational and capital investment for improved asset reliability for customers.

1.5.4 Interconnection

Hydro is preparing for the integration of its electrical system with the North American grid, which is anticipated to take place in 2018.[26] Hydro is evaluating opportunities and risks associated with interconnection and is ensuring that required tasks are completed on target. All of these initiatives will contribute to ensuring a smooth transition to interconnection with the North American grid, and ensure Hydro can continue to provide reliable service to its Island Interconnected System customers.[27]

[23] The measure is a combination of Hydro's service continuity data and Newfoundland Power service continuity data for loss of supply outages resulting from events on Hydro's transmission system. Therefore, the SAIFI and SAIDI data contained in Table 1-2 is a measure of the frequency and duration of service interruptions experienced as a result of Hydro system events and does not reflect interruptions to Newfoundland Power customers from issues on Newfoundland Power's system.
[24] This includes the January 2013 Winter storm which contributed 0.82 to End Consumer SAIFI and 5.26 to End Consumer SAIDI.
[25] This includes the January 2014 Events which contributed 3.43 to End Consumer SAIFI and 7.71 to End Consumer SAIDI.
[26] The Labrador-Island Link and the Maritime Link are anticipated to be in operation in 2018.
[27] The interconnection of Muskrat Falls is currently under review by the Board in its *Investigation and Hearing into Supply Issues and Power Outages on the Island Interconnected System – Phase Two.*

1.6 Financial Performance

Hydro's revenue requirement for the provision of safe, reliable, least cost electrical service is the sum of the return on rate base and other reasonable costs, which includes operating costs, fuel costs, power purchases, and depreciation.

Hydro's proposed revenue requirement has increased by $88.2 million in the 2019 Test Year over the Board approved 2015 Test Year, as shown in Figure 1-3. The increase in revenue requirement since 2015 is primarily a result of an increase in capital investment, and fuel and other costs, with an offsetting reduction in Hydro's weighted average cost of capital due to lower debt and changes in Hydro's capital structure.[28]

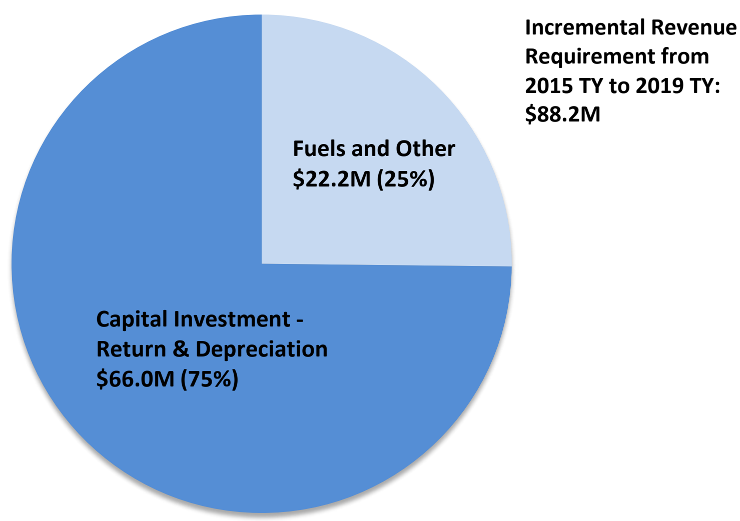

Figure 1-3 Incremental Revenue Requirement 2019 Test Year vs 2015 Test Year[29]

Based on current rates, Hydro would incur a net loss of $10.7 million in 2018, with a 2018 Test Year return on rate base of 3.84%, which is below the bottom of the approved return on rate base of 6.41% established for the 2015 Test Year.

[28] Hydro's weighted average cost of capital results in a decrease in Hydro's revenue requirement by $21.9 million, or 25% from the 2015 Test Year to the 2019 Test Year.
[29] Please refer to Chapter 4: Finance for more information on Hydro's incremental revenue requirement.

1.7 Conclusion

Hydro values and respects the Board's role and oversight of Hydro as a public utility. Hydro is committed to ensuring a cooperative and efficient hearing of this Application.

Hydro is effectively managing its business to ensure its costs and actions are prudent and reflect industry best practice for safe and efficient operations and least cost, reliable provision of electricity.

Hydro has implemented broad changes to its practices as a result of guidance and direction provided by the Board in recent years, all with the intent of improving its ability to ensure least cost reliable supply to its customers, and providing a high level of transparency and accountability to the regulator and customers.

Hydro is continually improving system reliability by completing asset renewal work, performing increased and timely maintenance, and adding necessary generation and transmission facilities. The Company is focused on meeting customers' electricity needs, rebuilding the aging electricity system, using newer and better software and processes to predict customers' power needs, and refining system response protocols. Hydro's new organizational structure has resulted in improved planning and management oversight and increased reliability.

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Chapter 2 Customers

2.1 Overview

Consistent with its legislated mandate, Newfoundland and Labrador Hydro (Hydro) ensures the reliable supply of least cost power to approximately 38,600 direct rural customers in more than 240 communities throughout the Province.[1] Hydro's distribution service areas are located on the Great Northern Peninsula, along the South Coast and White Bay – Baie Verte area, and includes most of the communities located in Labrador. Hydro also provides service to seven industrial customers and its utility customer, Newfoundland Power Inc. (Newfoundland Power). Table 2-1 provides the distribution of Hydro's customers within its service areas as of March 31, 2017. A map showing Hydro's service areas is provided in Schedule I of Exhibit 1.

Table 2-1 Hydro Customer Distribution

Customer Class	Island Interconnected	Island Diesel	Labrador Interconnected	Labrador Diesel	L'Anse au Loup	Total
Domestic	19,865	707	9,819	2,147	815	33,353
General Service[2]	3,060	84	1,418	520	199	5,281
Industrial	5[3]		2[4]			7
Utility	1					1
Total	**22,931**	**791**	**11,239**	**2,667**	**1,014**	**38,642**

Table 2-2 shows the total number of customers served by Hydro for the years 2012 through 2016. The average growth in the number of customers during this period is 255, or 0.7% per year.

[1] Customer total does not include 1,532 street and area lighting customers.
[2] Commercial customers fall into the General Service Customer Class.
[3] North Atlantic Refining Limited, Vale Newfoundland & Labrador Limited, Praxair Canada Inc., Teck Resources Limited, and Corner Brook Pulp and Paper Limited.
[4] Iron Ore Company of Canada and Wabush Mines.

Table 2-2 Hydro Customer Totals[5]

Year-end	2012	2013	2014	2015	2016
Total	37,584	38,030	38,251	38,379	38,602

In 2014, Hydro developed a Customer Service Strategic Roadmap for the period 2015-2017. The purpose of the roadmap is to provide a focus on improving service to Hydro's customers.[6] In 2015, this included the development of an Account Management Framework to guide Hydro's customer interfaces with key commercial and industrial customers as well as Newfoundland Power. In 2016, Hydro established an after-business hours customer call support service, launched a new mobile and web portal platform, and implemented a new Interactive Voice Response (IVR) telephone system. Hydro will continue the execution of its roadmap beyond 2017 with a focus on enhancing customer service processes and technology, and continuing to deliver improved service to customers.

Hydro's customer service satisfaction scores have remained strong in comparison to the Canadian Electricity Association (CEA) average and have shown an upward trend over the past two survey periods.[7] In the most recent customer survey, completed in the fall of 2016, Hydro's customer satisfaction increased to 90%, up from 84% in 2014.[8]

Hydro's commitment to customers also includes education and programs to help customers reduce their electricity usage and cost. Hydro will continue to help residential, commercial, and industrial customers conserve energy. The *Five Year Conservation Plan: 2016-2020* outlines

[5] Excludes street and area lighting customers.
[6] This report was filed with the Board of Commissioners of Public Utilities (the Board) on September 30, 2014. See also Request for Information (RFI) CA-NLH-322 from Hydro's 2013 Amended General Rate Application, available: http://www.pub.nl.ca/applications/NLH2013GRA-Amended/files/rfi/CA-NLH-322.pdf. An update to this report as required by Order No. P.U. 49(2016) is attached as Exhibit 3.
[7] As per the CEA Public Attitudes Survey, the CEA average was 55% for 2014 and 56% for 2016. Hydro averages were 84% and 90%, respectively.
[8] The percentage of customers surveyed that provided a rating of 7 or higher on the question "*In general, how satisfied are you with Hydro's customer service, on a scale from 1 to 10, where 1 is "not at all satisfied" and 10 is "very satisfied"?*".

energy efficiency program offerings for residential, commercial, and industrial customers.[9] The plan includes programs delivered in partnership with Newfoundland Power through the takeCHARGE program which offers rebates to encourage residential and commercial customers to reduce their electricity usage. It also contains programs that Hydro delivers directly to its customers in high cost isolated communities. The Industrial Energy Efficiency Program provides industrial customers with financial assistance and technical support to complete feasibility studies and capital upgrades to achieve electricity savings.

2.2 Serving Customers

Hydro is committed to meeting customer expectations through improved interactions utilizing a broad range of interfaces. The Company is focused on the open and transparent sharing of information about the electricity system and continues to emphasize communication with customers. Customers can access information or submit inquiries through a variety of channels, including telephone (toll free), email, the *myNLhydro* mobile and web portal platforms, as well as Hydro's website and social media channels.[10] These changes have been implemented as part of the Customer Service Strategic Roadmap.

On an annual basis, Hydro receives over 40,000 telephone calls, 4,000 customer emails, and issues over 470,000 electricity bills to its domestic, general service, industrial, and utility customers. Table 2-3 provides the distribution of customer initiated contacts from 2013 to March 2017.

[9] This report was filed with the Board on November 12, 2015.
[10] Hydro actively communicates with customers and shares system related information through its Twitter and Facebook accounts (@NLHydro) as well as a dedicated YouTube channel (www.youtube.ca/NLHydro).

Table 2-3 Customer Initiated Contacts

Year	2013	2014	2015	2016	2017-Q1
Customer Calls	48,067	45,230	43,922	42,519	22,527[11]
Emails	3,238	3,234	3,877	4,641	2,243
After-Hours Calls[12]				3,356	1,471
myNLhydro[13]				185	450
Total	51,305	48,464	47,799	50,701	26,691

In addition, Hydro responds to requests and inquiries through social media which generally allows information to be shared with customers and key stakeholders in real time. Hydro currently has more than 30,000 direct followers on its Twitter and Facebook accounts combined. The immediacy of interaction and ability to reach broad and varied audiences makes social media an effective communications tool for Hydro. In 2016, tweets from Hydro generated over 2.5 million impressions on Twitter, and Facebook posts by Hydro had a total reach of 1.3 million.[14]

In March 2016, Hydro implemented a Customer Assistance Database to electronically record all customer interactions. Prior to the implementation of this database, interactions were captured manually. This new system provides a database of all customer interactions in which Customer Service Representatives (CSRs) can share and maintain notes. It provides an historical view for each customer for each time they contact Hydro, which allows the CSRs to reference and improve the customer experience. The database also provides reporting and analytics, giving the customer service team a view of the various types of customer requests and inquiries, facilitating continuous improvement discussions.

[11] Hydro has experienced a high volume of customer calls during Q1-2017 due to Rate Stabilization Plan Refund inquiries.
[12] Hydro started using an after-hours call service in July 2016.
[13] *myNLhydro* is detailed in Section 2.2.1
[14] Reach is defined as the number of unique users who have viewed posted content.

2.2.1 Customer Service Strategy

As part of its customer service strategy, Hydro has made improvements to its processes and technology to better serve its customers. Notable initiatives include the establishment of an Account Management Framework, launching of an updated website, installation of a new IVR telephone system, engagement of an after-hours call centre service, and continued implementation of an automated meter reading (AMR) program.

Account Management Framework

In 2015, Hydro developed an Account Management Framework to guide its customer interfaces with key commercial and industrial customers as well as with Newfoundland Power. An essential requirement identified in Hydro's Account Management Framework was the creation of a dedicated account manager within Hydro's Customer Service department.[15] The Manager, Key Accounts is the representative for all of Hydro's Industrial Customers as well as other identified key commercial accounts, and proactively engages customers on key service and business areas, such as commercial arrangements, initial outage planning, unplanned outage response and follow-up, future power requirements, business development, continuous improvement, and promotion of Hydro's energy efficiency programs that are available to these customers.[16]

myNLhydro

In April 2016, Hydro launched a new mobile and web portal platform called *myNLhydro* that provides customers with access to their accounts anytime, anywhere, and on any device. As of March 2017, 4,922 Hydro customers were subscribed to *myNLhydro*. These customers are able to easily and conveniently:

- view account balance, payment history, and set up payment options online;

[15] Hydro's Account Management Framework is further described in Hydro's *Customer Service Account Management Framework Implementation Update Report*, submitted to the Board on January 13, 2017, in compliance with Order No. P.U.49(2016).
[16] The creation of this additional position also aligns with Recommendation 9.1 made by the Board's consultant, Liberty Consulting Group, as part of the Board's *Investigation and Hearing into Supply Issues and Power Outages on the Island Interconnected System – Phase One.* Please refer to *Report to the Board of Commissioners of Public Utilities – Review Supply Issues and Power Outages Island Interconnected System, December 17, 2014*.

- subscribe to text and email notifications for planned and unplanned power outages;
- view and report power outages online;
- subscribe to payment reminders via text and email notifications;
- sign up for paperless eBilling and equal payment plan;
- track and manage electricity usage in easy-to-read charts, set billing goals, and compare power usage year-over-year or against the aggregated average usage of other *myNLhydro* subscribers in their neighborhood; and
- submit inquiries and service requests.

Interactive Voice Response Telephone System

Hydro implemented a new IVR telephone system in November 2016 to better support its customers. The new IVR system provides enhanced functionality such as more specific outage information and links to Hydro's online customer outage notification in *myNLhydro* so customers receive up to date information.[17]

After-Hours Customer Support

In July 2016, Hydro established a formal, after-hours customer support arrangement with a third party vendor. This vendor has been trained in and provided with Hydro's process for dealing with outage calls and engages on-call staff when required to follow-up with customers. Hydro's customers, as well as Hydro's Energy Control Centre (ECC), have benefited from this new process. Removing responsibility from ECC operators to manage outage related calls has allowed ECC operators to focus on supporting the electricity system operation and restoration, while customers are served efficiently and effectively by the vendor.

2.2.2 Customer Education and Communication

Following the supply disruptions in January 2014, Hydro developed several protocols and processes to ensure clear and timely external communications with customers and key

[17] The IVR system provides the ability to identify outages by street address when customer enters a telephone number associated with the address.

stakeholders.[18] In 2014, Hydro and Newfoundland Power developed a joint storm/outage communication plan that clearly outlines the roles and responsibilities of each utility with expected timelines for communications, as well as tactics, messaging, and approval processes. In addition, the utilities developed three levels of alerts to advise customers of the status of the power supply in the province. The definition and use of these alerts is identified in the Advance Notification Protocol.[19] The goal of this Protocol is to provide early information to customers when there is potential for a supply shortage, for the Island or the Avalon Peninsula, to advise on specific actions asked of customers, and to better prepare customers for any potential impacts.

Hydro also communicates significant equipment outages to its customers and stakeholders through public advisories posted on Hydro's website and shared through social media when appropriate, as per Hydro's established Equipment Notification Protocol.[20]

Hydro recognizes the importance of educating customers and stakeholders on the provincial electricity system and is working hard to keep customers better informed. Customer education material can be found on Hydro's website and is regularly shared on Hydro's social media channels throughout the year and during specific events and/or outages. [21] In addition, traditional news media outlets have used Hydro's educational materials (both videos and infographics) on their websites, social media accounts and on television news broadcasts, to help explain certain topics.

[18] These protocols were developed after consultation with customers.
[19] Available at: https://www.nlhydro.com/winter/advance-notification-protocol/. The creation of the Advance Notification Protocol and other communications strategies aligns with Recommendations 37, 42, and 44 made by the Board's consultant, Liberty Consulting Group, as part of the Board's *Investigation and Hearing into Supply Issues and Power Outages on the Island Interconnected System – Phase One*. Please refer to *Report to the Board of Commissioners of Public Utilities – Review Supply Issues and Power Outages Island Interconnected System, Interim Report, April 24, 2014*.
[20] This protocol details corporate communications and system operations activities during significant transmission and/or generation equipment outages.
[21] Information is provided to customers in the form of videos, infographics and web content on the following; how to conserve energy, power outage safety, the Advance Notification Protocol, how the system works, restoring power after distribution or generation outages, communication during outages, under frequency load shedding, how outages are planned, power line safety, and cold load pick up.

2.3 Measuring Customer Satisfaction

Hydro completes customer satisfaction surveys to obtain customer feedback and seek opportunities for improvement as well as to gather information on the success of newly implemented initiatives. Surveys are conducted with Hydro's residential and key account customers. In addition to these in-depth surveys, Hydro has also implemented transactional surveys.[22]

2.3.1 Residential and Commercial Satisfaction

Hydro conducts biennial residential and commercial customer satisfaction surveys. In 2009, Hydro introduced commercial surveys at two year intervals, and since 2012, has conducted residential and commercial customer satisfaction surveys on an alternating two-year cycle. In addition to supporting cost savings,[23] this interval allows time for Hydro to develop and execute plans that can have an impact on customer satisfaction and have time to produce quantifiable results from one survey to another.

Hydro's customer service satisfaction scores have remained strong in comparison to the CEA average of 56% based on its most recent 2016 customer satisfaction survey results.[24] Hydro's most recent residential customer satisfaction survey was initiated in September 2016 with 90% of residential customers providing a rating of 7 or higher when asked to rate their overall satisfaction with Hydro on a 10 point scale, with 1 being 'not at all satisfied' and 10 being 'very satisfied'. The 2016 rating is an increase of 6% from 2014 and 10% from 2012. The most recent commercial customer survey was completed in December 2014 and resulted in an 84% satisfaction rating, based on the same point system as described above for the residential survey. The next commercial customer satisfaction survey is scheduled for 2017. Hydro is targeting a commercial customer satisfaction rating of greater than or equal to 80%.

[22] These transactional surveys occur bi-weekly.
[23] Biennial satisfaction surveys result in approximately $30,000 in annual savings.
[24] Canadian Electricity Association: 2016 National Public Attitudes Survey. The 2015 CEA average was 59%.

Figure 2-1 shows the trend of Hydro's residential customer satisfaction from 2006 to 2016. The recent trend suggests that the actions being taken through Hydro's Customer Service Strategy are providing positive service impacts for residential customers.

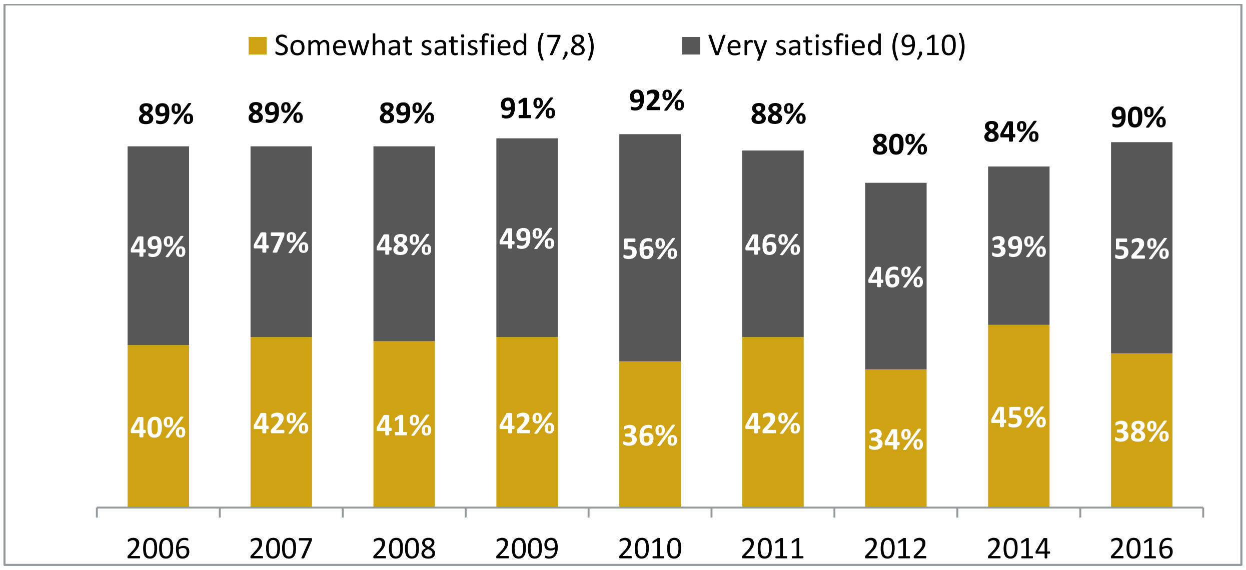

Figure 2-1 Residential Customer Satisfaction Index 2006 to 2016

Figure 2-2 shows the trend of Hydro's commercial customer satisfaction from 2007 to 2014.

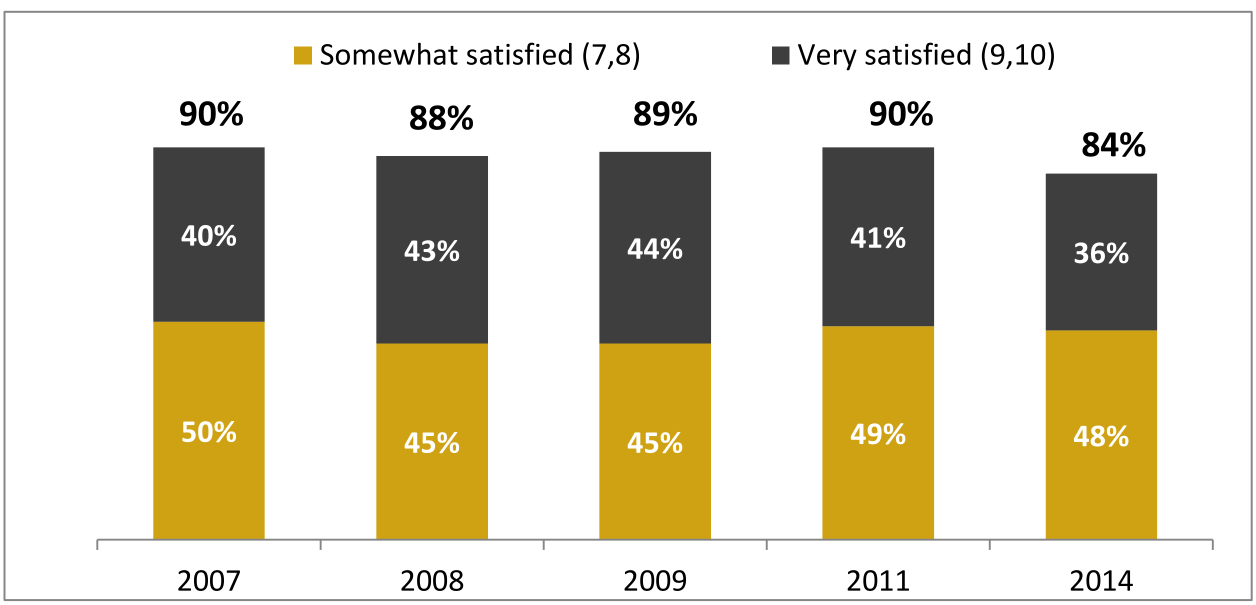

Figure 2-2 Commercial Customer Satisfaction Index 2007 to 2014

In January 2017, Hydro implemented a transactional survey process to receive timely feedback on the services that Hydro's customer call centre provides to customers. Transactional surveys are conducted bi-weekly through an automated outbound calling service where customers are asked to rate their most recent experience with Hydro's customer call centre in relation to billing, power outages, payments, or new service inquiries. The survey asks four questions to focus on the quality of service received, knowledge of customer service staff, and measure first contact satisfaction.[25] Survey result reports highlight the service provided and are reviewed with customer service staff. Transactional survey results for the period of January to March 2017 show that 88% of Hydro's customers are satisfied with the service they received.[26]

2.3.2 Key Account Customers

In November 2015, Hydro engaged its key account customers to solicit feedback on their current services and highlight issues of importance.[27] Topics included meeting customer's needs, customer service, account management, billing, energy efficiency, communication, and overall service. When asked about the overall service received from Hydro, the respondents provided an average rating of 7.8 out of 10, and provided clear input for account management planning.

2.3.3 Newfoundland Power

The vast majority of energy generated and transmitted by Hydro is sold to its largest customer, Newfoundland Power, which distributes it to approximately 265,000, or 92%, of island

[25] Customers are asked to rate their experience on a scale of 1 to 5, with 1 being Completely Dissatisfied, and 5 being Completely Satisfied: Q1 – How courteous was the person who answered your call; Q2 – How knowledgeable was the person who answered your call; Q3 – How satisfied were you with the overall level of service you received when you called; and Q4 – Were we able to address all your needs with one call to our Call Centre, press 1 for yes, press 2 for no.

[26] To March 2017, the average completion rate for transactional surveys was 17%, since original implementation in January 2017.

[27] Given the small number of potential participants, a qualitative approach was used for the survey. A total of 16 companies were approached for this survey. Responses were received from 13 of the 16 key account customers. This also aligns with Recommendation 9.2 made by the Board's consultant, Liberty Consulting Group, as part of the Board's *Investigation and Hearing into Supply Issues and Power Outages on the Island Interconnected System – Phase One.* Please refer to *Report to the Board of Commissioners of Public Utilities – Review Supply Issues and Power Outages Island Interconnected System, December 17, 2014*.

customers. While Hydro does not directly serve these customers it acknowledges the reach of its service to them. In 2016, Hydro engaged representatives at different levels of Newfoundland Power on how it can help serve and build a stronger relationship between the two companies with the aim of improving the end-user customer experience.[28] Topics included customer service, communication, account management, infrastructure, billing, and collaboration. The emerging theme was collaboration and partnership, and that Hydro and Newfoundland Power should be working together to support customers in the best manner possible. Hydro agrees with this result and will continue working with Newfoundland Power in support of safe and reliable service for all customers.

2.4 Balancing Customer Service and Costs

Costs associated with customer service include the costs of Hydro's day to day interactions with customers, meter reading, billing, call centre operations, meter shop, key accounts, and technical services. Table 2-4 provides the actual Customer Service operations and maintenance (O&M) costs from 2013 to 2016, and the forecast amounts from 2017 to the 2019 Test Year.

Table 2-4 Customer Service O&M Costs 2013 to 2019 TY ($000s)

Year	2013	2014	2015	2016	2017F	2018 TY	2019 TY
O&M	3,314	3,576	4,075	3,791	4,035	4,064	4,099

To manage customer service costs, Hydro has invested in a number of technologies, including the adoption of new billing and customer care software and automated meter reading. Hydro also encourages customers to use technology to initiate interactions, such as through its website or social media and through enrollment in electronic billing (eBilling). Hydro continues to review its controllable costs to determine efficiencies.

[28] Research similar to that undertaken with Hydro's industrial and commercial accounts was initiated to determine appropriate metrics.

2.4.1 Automated Meter Reading

Hydro is increasing its use of AMR technology for customer metering. For example, the AMR capital project for Happy Valley, beginning in 2017 and ending in 2018, will result in a reduction of two full time equivalent positions (FTEs) and will reduce associated operating costs by $296,000 in 2019.[29] AMR also contributes to improvements in customer service through reduced meter reading estimates and errors associated with manual reading, the availability of more detailed energy usage information, consolidated billing and billing dates, improved employee safety by reducing risk exposure when accessing properties, and environmental benefits through reduced vehicle use and fuel consumption.

2.4.2 Billing Software

In November 2016, Hydro started the implementation of a new software application to support industrial billing.[30] The new application, Itron's MV-PBS for complex billing, will provide accurate and timely billing for Hydro's industrial and wholesale customer accounts and eliminate manual processes to improve billing to Hydro's largest customers. MV-PBS will also integrate with the existing industrial meter data collection application, automate bill calculations, reduce risk associated with manual calculations, decrease the meter-to-bill timeframe, and provide audit tracking and reporting capabilities. The application is scheduled to be operational by the end of 2017.

2.4.3 Business Systems Transformation Program

Through the shared services provided by its parent company, Nalcor Energy (Nalcor), Hydro is a client of the corporate Business Systems Transformation Program.[31] This program will provide enhanced functionality and processes for Hydro's operations. One of the main projects of this program is the upgrading of the organization's current Enterprise Resource Planning System from JD Edwards World to JD Edwards Enterprise One (E1). As part of the E1 upgrade, a separate customer care and billing product, Utiligy-360, will be implemented to work with E1 to

[29] Approved in Hydro's 2017 Capital Budget Application (CBA) pursuant to Board Order P.U. 45(2016).
[30] Approved in Hydro's 2016 CBA pursuant to Board Order P.U. 33(2015).
[31] Please see Chapter 3: Operations for more information on the Business System Transformation Program.

automate processes and provide data on all customer interactions. Utiligy-360 will record and track customer interactions, provide access to customer information, integrate processes, and provide ability for data trend analysis producing a more streamlined, accurate, and effective customer experience.

2.4.4 eBilling

To support management of customer service costs, Hydro's Customer Service Strategy includes the promotion of eBilling. In 2015, Hydro developed a five-year plan to increase electronic billing subscriptions. In 2015, 5,092 of Hydro's customers signed up to eBilling. This number increased to 6,748 in 2016. Hydro is continuing its focus on eBilling and currently has 7,917, or 20%, of its customers subscribing to this service.[32]

2.5 Conservation and Demand Management

Since 2008, Hydro and Newfoundland Power have partnered to deliver the takeCHARGE program which offers incentive programs to assist residential and commercial customers in reducing their electricity usage. The utilities have jointly designed and implemented three portfolios of programs for electricity customers throughout the province.[33]

Current takeCHARGE programs offered through the joint utility model are available for residential and commercial customers and provide rebate options to promote energy efficiencies to electricity consumers in each sector. Hydro will continue its partnership with Newfoundland Power to deliver the takeCHARGE program to customers throughout the province. Participation in the residential insulation and thermostat programs is highest among customers located in Hydro's interconnected areas where electric heat use is more

[32] An informal poll conducted by the CEA in Q1-2017 indicates an average of 26% eBill participation among 10 Canadian utilities that responded to the poll.

[33] Hydro and Newfoundland Power have filed three five-year plans with the Board: the *Five-Year Energy Conservation Plan 2008 – 2013* pursuant to Order No. P.U. 8 (2007), filed June 27, 2008; the *Five-Year Energy Conservation Plan 2012 – 2016*, filed September 14, 2012; and the *Five-Year Conservation Plan 2016 – 2020*, filed November 12, 2015.

predominant. Interest in Hydro's commercial programs is consistent among commercial customers in both interconnected and isolated diesel areas.
In addition to takeCHARGE programming, since 2009, Hydro has coordinated with the Provincial Government on the *Coastal Labrador Energy Efficiency Pilot Program*, the *Real Time Monitoring Pilot Project*, and presently on the *Home Energy Efficiency Loan Program* that will run from 2017 to 2019.

Hydro also delivers programs that are specific to its customers located in higher cost isolated diesel areas. The objective in Hydro's isolated diesel areas is to help customers save energy by providing outreach, education, and energy efficient products to residential and commercial customers where access to such tools is limited. Since its launch in 2011, Hydro's *Isolated Systems Community Energy Efficiency Program* has resulted in training for local community representatives, and installation of over 70,000 energy efficient products in homes and businesses in 21 isolated diesel systems. The accumulated annual energy savings from residential and commercial energy efficiency programs delivered in the isolated diesel systems from 2009 to 2016 is 6,515 megwatt-hours (MWh), equivalent to 9% of the total energy sales in the isolated diesel systems in 2016.

Hydro's *Industrial Energy Efficiency Program* is a customized program that offers support and financial incentives based on energy savings for the retrofit of industrial process equipment for Hydro's transmission level customers. Participation in the industrial program has been variable given the small number of industrial customers in the province. Promotion of the industrial program is now included under Hydro's Account Management Framework to support improved project planning and scheduling and continual encouragement of customers to avail of the program.

Tables 2-5 and 2-6 provide the actual annual energy savings and costs for Hydro's energy conservation programs from 2009 to 2016, and the forecasts to 2019.

Table 2-5 Hydro Energy Conservation Program Energy Savings (MWh)

	2009-2016	2017F	2018F	2019F	Total
Residential	9,962	572	617	215	**11,366**
Commercial	2,725	644	710	758	**4,837**
Industrial[34]	25,772	-	-	-	**25,772**
Total	**38,459**	**1,216**	**1,327**	**973**	**41,975**

Table 2-6 Hydro Energy Conservation Program Costs ($000s)

	2009-2016	2017F	2018F	2019F	Total
Residential	6,155	1,478	1,478	1,478	**10,589**
Commercial	1,025	362	362	362	**2,111**
Industrial[35]	1,813	390	390	390	**2,983**
Total	**8,993**	**2,230**	**2,230**	**2,230**	**15,683**

Changes to the provincial electrical system costs are expected with the integration of Muskrat Falls and interconnection with the North American grid. As a result, the utilities anticipate a review of the multi-year conservation plan midway through the period (2016-2020) to take any cost changes into consideration.

2.5.1 Internal Energy Efficiency

Since 2008, Hydro has placed a specific focus on internal energy efficiency at its own facilities. Hydro has been pursuing internal energy efficiency savings through initiatives that reduce electricity consumption at its facilities and continues to review operating and capital projects to identify any redesign opportunities that can improve energy use. The aim is to reduce operating costs and contribute to overall cost containment, a portion of which is allocated to rural customers, and therefore contributes to Rural Deficit reduction. Such opportunities include upgrades to diesel plant lighting, service buildings and site lighting, space heating seasonal

[34] Due to the magnitude and variability of energy savings in the Industrial Program, no energy savings are forecast until customers provide some indication of participation.
[35] Some costs are forecast for the Industrial Program to make allowance for potential participation.

lockout program at remote sites, and HVAC controls and equipment improvements. Table 2-7 provides the cummulative annual internal energy efficiency savings from 2009 to 2016, and the forecast to 2019.

Table 2-7 Hydro Internal Energy Efficiency Savings

	2009-2016	2017F	2018F	2019F	Total
MWh	15,677	220	280	390	**16,567**

2.6 Net Metering

On July 28, 2015, the Government of Newfoundland and Labrador released the Provincial *Net Metering Policy Framework*. In addition to approving a provincial framework, the Province also issued an exemption order pursuant to section 14(1) of the *Electrical Power Control Act, 1994*, to facilitate development and implementation of a net metering program by Hydro and Newfoundland Power. Under the terms of the framework, Hydro and Newfoundland Power were responsible for developing and implementing a net metering program for their respective customers, consistent with the policy direction set forth in the framework. The objective of the net metering program is to provide customers with the option to offset their energy usage through their own small-scale renewable generation. The *Net Metering Policy Framework* sets a provincial subscription limit of 5 MW for all net metering customers' generating facilities combined, and an individual generating capacity limit not to exceed the customer's load requirement, to a maximum of 100 kW. On December 2, 2016, Hydro filed an application with the Board seeking approval to implement a Net Metering Service Option for its rural customers. This application was approved in Order No. P.U. 17(2017). Hydro has established the internal processes required to support net metering requests from customers as of July 1, 2017. Information was also provided on Hydro's website, on social media, and in a bill insert to assist customers with details and questions about Hydro's Net Metering program.

2.7 Identification of the Rural Subsidy on Customer Bills

In Order P.U. No. 49(2016), the Board directed Hydro to file a report in relation to the identification of the rural subsidy[36] on customers' bills, including practices in other jurisdictions, other options to address transparency concerns, information customers would like to have on their bills, and other concerns. Hydro's report is attached as Exhibit 4.

In developing this report, Hydro conducted surveys with rural customers to determine the type of information customers would like to see on their bills with respect to the rural subsidy. A majority of customers indicated that they would like to see information on the rural subsidy. Hydro proposes to work with Newfoundland Power to develop a communications plan for the rural subsidy to ensure alignment.

2.8 Conclusion

Over the past three years, there has been a stronger organizational focus placed on customer service throughout Hydro. Investments have been made in technology (software and hardware), processes, training, and the addition of new roles such as the Manager, Key Accounts. Hydro continues to meet the reasonable service expectations of its customers while maintaining a balance between service and costs.

[36] Revenues from Hydro's Rural Customers, with the exception of those on the Labrador Interconnected System, do not fully recover the cost to serve those customers, resulting in a deficit in Hydro's revenue.

Chapter 3 - Operations

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Chapter 3 Operations

3.1 Overview

Newfoundland and Labrador Hydro (Hydro) is focused on delivering value to its electricity customers by managing costs, ensuring a reliable electrical system, committing to safe and environmentally sound practices, and ensuring it is ready for integration with the North American grid.

Since its last general rate application (GRA), Hydro has undergone significant organizational changes. The purpose of these changes was to create greater operational independence from its parent company, Nalcor Energy (Nalcor), and to ensure continued focus on the Company's core business as a regulated utility.

Hydro is focused on providing least cost, reliable service to its customers through appropriate asset management practices. Hydro's asset base is aging and requires significant investment and maintenance. In 2017, Hydro will invest approximately $370 million in capital projects as part of its reliability plan to upgrade the provincial power grid and meet customer demands for electricity. A high level of investment will continue as Hydro essentially rebuilds many of its facilities to ensure long-term reliable electricity to customers.

The Company has modified the way it operates the electrical system and has implemented a number of operational improvements focused on ensuring its customers are provided with reliable service and are aware of what is happening on the system.

While Hydro does not directly serve all customers in the province, its operations affect all end consumers of electricity. A newly developed reliability metric to measure its impact on the end user consumer of electricity in the province drives a reliability and customer focused culture.

A major proponent of managing the electrical system is the planning of customer load requirements. Hydro has updated its planning models to better reflect the electrical system which provides more accurate analysis of system demands and capabilities. The Company continues to review the load requirements of its customers to ensure it can reliably meet growing demand.

In 2017, Hydro plans to invest approximately $134 million in the operations and maintenance of its system. These deliberate measures are to ensure the delivery of safe, reliable, least cost power for its customers.

Hydro is preparing for interconnection to the North American grid. Through interconnection management, the Company is evaluating opportunities and risks associated with this interconnection and ensuring the tasks required for successful integration are on target and disruptions to customers are well managed and minimized.

Hydro is committed to ensuring the prudent management of costs, without compromising safety and reliability.

3.2 Hydro's Organizational Structure[1]

In mid-2016, changes to Hydro's organizational structure were implemented to ensure focus on the regulated business and a clear separation from Nalcor, while continuing to provide safe, reliable, least cost service to customers.[2] The outcome of this change was the creation of a separate and dedicated executive team for Hydro. This new executive structure reflects an organizational model required to operate the Company on an independent, standalone basis to ensure continued focus on Hydro's core mandate. The revised executive structure includes a President of Hydro, who is accountable for all functions associated with delivering utility service, five Vice Presidents, and General Counsel. The President, each of the Vice Presidents, and General Counsel have no shared responsibilities with any other Nalcor line of business and

[1] Please refer to Exhibit 2 for additional information on the responsibilities of each division of Hydro.
[2] Nalcor Energy's June 15, 2016 media release, available https://nalcorenergy.com/press-releases/nalcor-ceo-announces-organizational-changes/.

are accountable directly to the President of Hydro.[3] The revised structure was designed to increase focus on system reliability and customer service, to enhance regulatory focus, and to ensure Hydro is prepared for the changes that will result from the interconnection to the North American grid.

The primary changes were:

- the creation of a separate and dedicated Executive team for Hydro. Figure 3-1 show the new Executive structure of Hydro;
- reduced reliance on the parent company for services that were previously shared among the Nalcor lines of business; and
- the transfer of certain functions that provided common services[4] to all Nalcor lines of business and recovered costs through an Administration Fee from Hydro to Nalcor. The functions and specific services that were transferred include services in the areas of human resources, safety, and information systems.[5] Hydro now incurs a fee for these services from Nalcor, but maintains control and accountability for all services and costs to Hydro.

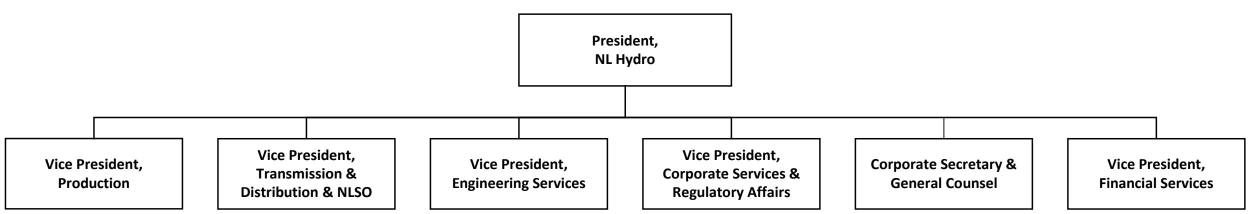

Figure 3-1 Executive Structure

[3] These changes align with Recommendation 10.2 made by the Board of Commissioners of Public Utilities' (the Board) consultant, Liberty Consulting Group, as part of the Board's *Investigation and Hearing into Supply Issues and Power Outages on the Island Interconnected System – Phase One.* Please refer to *Report to the Board of Commissioners of Public Utilities – Review Supply Issues and Power Outages Island Interconnected System, December 17, 2014*.

[4] Common Services are those services provided by certain departments as noted in the Intercompany Transaction Costing Guidelines in Exhibit 5.

[5] Please refer to Exhibit 5.

3.2.1 Full Time Equivalents

Table 3-1 provides Hydro's workforce as expressed in net full-time equivalents (FTEs) from the 2015 Test Year to the 2019 Test Year.[6] The net FTEs reflect the organizational structure changes made in 2016.[7] The reduction in net FTEs in 2016 includes 41 positions in the Information Systems department that were transferred from Hydro to Nalcor. The increase in FTEs in the 2017 forecast includes the impact of the Hydro reorganization.

Table 3-1 Net FTEs from 2015 TY to 2019 TY

	2015 TY	2015 Actual	2016 Actual	2017 Forecast	2018 TY	2019 TY
Net FTEs	888	861	809	860	852	850

3.3 Reliability and Customer Focus

Hydro is committed to providing safe, reliable, least cost electricity to its customers. This requires that Hydro continuously maintain, refurbish, renew, and expand its generation, transmission, distribution assets, and supporting systems. The Company has modified the way it operates the electrical system to ensure customers are provided with reliable service and information on system events. Hydro is also committed to performing necessary system work with minimal customer interruption and plans to re-introduce live-line work at the distribution level to reduce the level of planned outages.

3.3.1 Asset Management and Capital Investment

The majority of Hydro's installed assets, like the hydroelectric installation at Bay d'Espoir,[8] the Holyrood Thermal Generating Station (Holyrood), and much of Hydro's transmission and distribution systems, are more than 40 years old. In addition, many other generation assets, such as the Stephenville gas turbine, the Hardwoods gas turbine, and the Hinds Lake Generating Station are more than 30 years old. Maintaining Hydro's systems in reliable

[6] Net FTEs are Hydro based employees, plus time charged to Hydro, less time charged from Hydro to the other Nalcor Lines of Businesses, and excludes FTEs associated with Administration fees charged by Nalcor.
[7] Please refer to Exhibit 2 for an overview of Hydro's organization, including organization charts by division and department.
[8] The Bay d'Espoir Generation Station is 50 years old.

operating condition for its customers is accomplished through a combination of planned maintenance, rehabilitation of existing assets, and replacement of assets that have reached the end of their operating lives.

Hydro's capital plan is anchored to its long term asset management practices.[9] As Hydro's electrical system ages and customer demand grows, deliberate and continued investment in maintenance and system upgrades are required to provide reliable service to customers.

Hydro's strategic spending priorities for its capital program are:

- addressing mandatory issues such as ensuring the safety of Hydro employees, its contractors, and the general public, compliance with legislative and regulatory requirements, and managing environmental risks;
- meeting projected load growth and customer requests;
- applying a consistent asset maintenance philosophy to ensure system reliability and maintaining acceptable asset performance as identified by operating experience, maintenance history, condition assessments, performance evaluation, and monitoring; and
- achieving cost efficiencies.

Hydro has prudently increased investment in its capital program.[10] In 2016, Hydro spent approximately $204 million on capital work. In 2017, Hydro plans to spend $370 million. These investments, including the new transmission line TL267 from Bay d'Espoir to Western Avalon, are necessary to secure the long-term reliability of the system for Hydro's customers.[11]

[9] Hydro defines asset management as the comprehensive management of asset requirements, planning, procurement, operations, maintenance, and evaluation in terms of life extension or rehabilitation, replacement, or retirement to achieve maximum value for stakeholders based upon the required standard of service to current and future generations. It is an holistic, cradle to grave lifecycle view on how to manage assets.

[10] More information on Hydro's capital expenditures is located in Section 3.7.3 and Exhibit 6.

[11] From 2015 to 2018, an estimated total of $292 million will be expended on TL267. This project was approved in Order No. P.U. 53(2014).

3.3.2 Operational Improvements

In recent years, Hydro has implemented a number of operational improvements focused on ensuring the reliable supply of electricity to its customers.[12] This includes:

- daily system status meetings which assess power supply capability and reserves, and other conditions that could impact the reliability of the Island Interconnected System;
- a new operating instruction which provides a method of assessing Avalon capability and reserves;[13]
- the maintenance of spinning reserves[14] equal to the capacity of the largest online unit[15] and an additional 70 MW of available reserve to cover performance uncertainties;[16]
- the operation of standby generating units[17] in advance of potential outage events to cover generation or transmission outages equal to the worst case contingency for either the Island or Avalon Peninsula rather than starting them after an event has occurred; [18] and
- protocols and processes to ensure clear and timely external communications with customers and key stakeholders about the status of the power supply in the province.[19]

Hydro is also in the process of developing procedures to safely re-introduce hotline work, or live-line work, on its distribution system to lessen the impact of system work on customers.[20]

[12] For more details regarding Hydro's operational changes please refer to Hydro's report *Establishing a Robust Operational Philosophy and Enhancing Skills and Capabilities Relating to Systems Reliability and Analysis* filed with the Board on March 30, 2017 as part of the *Board's Investigation and Hearing into Supply Issues and Power Outages on the Island Interconnected system – Phase One*.

[13] Operating Instruction T-096 "Avalon Capability and Reserves."

[14] Spinning reserve is the unloaded generation that is synchronized and ready to serve additional demand.

[15] For the current system, this is equal to 170 MW when Unit 1 or 2 at Holyrood is online, and is otherwise 154 MW, which is the capacity of Bay d'Espoir Unit 7.

[16] This operational change aligns with Recommendation 2.7 made by Liberty as part of the Board's *Investigation and Hearing into Supply Issues and Power Outages on the Island Interconnected System – Phase One.* Please refer to the *Report to the Board of Commissioners of Public Utilities – Review Supply Issues and Power Outages Island Interconnected System, December 17, 2014*.

[17] This includes the Hardwoods gas turbine, Stephenville gas turbine, Holyrood gas turbine, Holyrood diesel standby generating units, Hawkes Bay diesel plant, and St. Anthony diesel plant.

[18] This action is taken in advance of planned maintenance outages or anticipated system events.

[19] For more information on the tools used by Hydro to communicate with its customers, please refer to Chapter 2: Customers.

[20] Live-line work refers to the maintenance and upgrade of electrical equipment, often at high voltage, while the equipment is still energized. Live-line work techniques can be used to safely complete a variety of maintenance

The application of live-line techniques as a maintenance approach will allow Hydro to safely complete critical work while avoiding disruption of power to customers. Hydro has developed a plan to begin safely completing live-line work with internal forces within the next three years.[21] In the meantime, Hydro will utilize specialized contractors trained in live-line work techniques to perform specific live-line maintenance, training of Hydro personnel, and to facilitate the transfer of knowledge. In 2016, Hydro utilized live-line techniques to complete work on the system and reduce the number of required outages. This included an emergency repair to a damaged splice on one of its 230 kV transmission lines on the Avalon Peninsula, a voltage upgrade in Goose Bay, bus reconfiguration in the Happy Valley Terminal Station, and replacement of insulators on the Bottom Waters system.

3.3.3 System Event Preparedness

Hydro's customers expect the Company to respond to system events immediately. Hydro has made a number of advances in recent years to strengthen its ability to respond to system events. These measures include:[22]

- reviewing and implementing, when required, storm preparation protocols in advance of significant weather events;
- staffing its facilities in advance of adverse system conditions, which can contribute to faster response time and reduced outage durations for customers;
- entering into a number of capacity assistance agreements that permit Hydro to call upon its industrial customers to provide or curtail power, which helps maintain generation reserves on both the Island Interconnected System and the Avalon Peninsula

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activities, including changing and testing of insulators, replacing damaged sections of conductors, replacing transmission poles, and other maintenance activities. There are many advantages to utilizing live-line work techniques. It allows a utility to complete maintenance activities with fewer planned outages, thus maintaining continuity of service for customers, and provides greater flexibility for maintenance activities, allowing for efficiency of operations.

[21] The plan includes an internal review of policies, procedures, training, tools, and equipment to determine and close any existing gaps to safely completing energized work.

[22] For more details regarding Hydro's operational changes please refer to Hydro's report *Establishing a Robust Operational Philosophy and Enhancing Skills and Capabilities Relating to Systems Reliability and Analysis* filed with the Board on March 30, 2017, as part of the *Board's Investigation and Hearing into Supply Issues and Power Outages on the Island Interconnected system – Phase One*.

System and, in the case of significant system events, helps to lessen the impact on residential customers. These agreements provide Hydro with operational flexibility during times of higher demand and/or unforeseen system events to ensure system reliability;[23]

- the development of a joint storm/outage communication plan with Newfoundland Power, including the Advance Notification Protocol, to inform customers and key stakeholders of system events and to better prepare customers for any potential impacts;[24] and
- a Corporate Emergency Response Plan (CERP) that provides clear and concise guidelines for actions to be taken by Hydro's Executive and Management Team during emergency situations.[25]

Hydro's continued investment in these preparedness measures ensures it can meet customer expectations.

3.4 Reliable Operations – System Performance

Hydro is responsible for managing the reliable performance of its electrical system which is constructed and maintained to appropriate standards.[26]

As the main supplier of generation to Newfoundland Power, Hydro recognizes that its performance affects more than just its direct customers. In 2016, Hydro moved towards a more

[23] A description and summary of the capacity assistance agreements currently in place can be found in Hydro's *Capacity Assistance Report 2016-2017*, filed with the Board on April 17, 2017.

[24] Please refer to Chapter 2: Customers for further information regarding Hydro's communication with its customers and key stakeholders.

[25] The CERP provides essential Corporate support to assist in: safeguarding people, property and the environment; responding to electrical system related events; responding to outages and supporting restoration plans; revival of operations and promoting business continuity; and providing accurate emergency response information to government, regulatory, and community response agencies. Hydro's current CERP also aligns with recommendations made by Liberty as part of the Board's *Investigation and Hearing into Supply Issues and Power Outages on the Island Interconnected System – Phase One.* Please refer to *Report to the Board of Commissioners of Public Utilities – Review Supply Issues and Power Outages Island Interconnected System, December 17, 2014*.

[26] A description of Hydro's service areas is provided in Exhibit 1. Electrical systems, including Hydro's, are not constructed, or expected, to fully withstand all extreme weather conditions. Hydro adheres to the Canadian Standards Association (CSA) Engineering Standards, and follows appropriate guidelines from associations such as the Institute of Electrical and Electronics Engineers (IEEE), the International Electrotechnical Commission (IEC), and the American Society of Mechanical Engineers (ASME).

customer focused reliability model, taking into account the impact on the end user, or end consumer, of electricity.

Further information regarding Hydro's reliability performance is located in Exhibit 7.

3.4.1 End Consumer Reliability

Hydro utilizes an End Consumer Reliability performance index to measure reliability to all end use consumers of electricity supplied by Hydro in the province.[27] Table 3-2 shows the End Consumer System Average Interruption Frequency Index[28] (SAIFI) and System Average Interruption Duration Index[29] (SAIDI) from 2012 to 2016.

Table 3-2 End Consumer Performance[30]

	2012	2013[31]	2014[32]	2015	2016
SAIFI	1.25	2.14	5.15	2.00	1.30
SAIDI	1.88	8.61	10.58	3.07	2.42

Since 2014, Hydro's End Consumer Performance for SAIFI and SAIDI have improved by approximately 75% and 77%, respectively.

[27] End consumer reliability is a performance index that was developed to measure the reliability of Hydro's systems in meeting the demand of all end users (consumers) of electricity in the province, including those not supplied directly by Hydro.
[28] System Average Interruption Frequency Index is a reliability key performance indicator which measures the average cumulative number of sustained interruptions per customer per year.
[29] System Average Interruption Duration Index is a reliability key performance indicator and it measures service continuity in terms of the average cumulative duration of outage hours per customer served during the year.
[30] The measure is a combination of Hydro's service continuity data and Newfoundland Power service continuity data for loss of supply outages resulting from events on Hydro's transmission system. Therefore, the SAIFI and SAIDI data contained in Table 3-2 is a measure of the frequency and duration of service interruptions experienced as a result of Hydro system events and does not reflect interruptions to Newfoundland Power customers from issues on Newfoundland Power's system.
[31] This includes the January 2013 Winter storm which contributed 0.82 to End Consumer SAIFI and 5.26 to End Consumer SAIDI.
[32] This includes the January 2014 Events which contributed 3.43 to End Consumer SAIFI and 7.71 to End Consumer SAIDI.

3.4.2 Transmission Reliability

Transmission reliability is measured in terms of interruptions and outage duration minutes per delivery point, or transmission SAIFI (T-SAIFI) and transmission SAIDI (T-SAIDI), respectively.[33] Table 3-3 provides Hydro's T-SAIFI and T-SAIDI performance for 2012 to 2016, including planned and forced outages.

Table 3-3 Transmission Performance (Planned and Forced Outages) – All Regions

	2012	2013[34]	2014[35]	2015	2016
T- SAIFI	1.87	3.45	3.78	3.10	2.86
T- SAIDI	170.79	468.45	457.71	476.63	324.73

Hydro's T-SAIFI and T-SAIDI has increased since 2012, mainly due to an increase in planned power outages to complete planned maintenance and capital improvements. The re-introduction of live-line work will improve both the T-SAIFI and T-SAIDI indices.

3.4.3 Distribution Reliability

Hydro's distribution reliability for its direct customers is measured in terms of interruptions and outage duration hours per customer. Table 3-4 provides Hydro's SAIFI and SAIDI performance for the period 2012 to 2016.

Table 3-4 Distribution Performance (Planned and Forced Outages) – All Regions

	2012	2013	2014	2015	2016
SAIFI	4.40	5.76	6.75	6.95	6.62
SAIDI	8.31	18.85	18.32	17.54	15.68

One of the main contributors to SAIDI from 2013 to 2015 was a series of planned outages in Wabush to upgrade the Wabush Substation and planned outages in Labrador City to complete

[33] A delivery point is the point of supply where the energy from the Bulk Electric System is transferred to the distribution system, Industrial customers, or Utility customer.
[34] This includes the January 2013 Winter storm which contributed 0.73 to T-SAIFI and 73.41 to T-SAIDI.
[35] This includes the January 2014 Events which contributed 0.68 to T-SAIFI and 120.50 to T-SAIDI.

the voltage conversion project. The main contributors to SAIDI in 2016 were unplanned outages in the Great Northern and Connaigre Peninsulas. In March 2016, all customers north of Cow Head experienced an interruption due to a hardware failure on transmission line TL259. In May 2016, customers on the Connaigre were affected by a forest fire under transmission line TL220 and equipment failure at the Barachoix Terminal Station.

3.4.4 Generation Reliability

Hydro measures and reports on the forced outage rates of its generating facilities.[36] The forced outage rates of Hydro's generating units are currently recorded using two measures: Derated Adjusted Forced Outage Rate (DAFOR) for the hydraulic units and thermal units,[37] and Utilization Forced Outage Probability (UFOP) for the gas turbines.[38]

Hydraulic Generation Performance

Table 3-5 provides Hydro's hydraulic generation performance for the period 2012 to 2016.

Table 3-5 Hydraulic Generation Performance – DAFOR

	2012	2013	2014	2015	2016
Hydraulic DAFOR	0.95	0.56	5.97	2.66	5.51

Equipment issues at the Bay d'Espoir Generation Station have impacted Hydro's DAFOR performance since 2014. Hydro's DAFOR performance remains stronger than the national CEA five year average of 6.59%.

[36] Included in the forced outage rates are outages that remove the unit from service completely, as well as instances when units were derated. If a unit's maximum output is reduced by more than 2%, the unit is considered derated by CEA guidelines. Per CEA guidelines, to take into account the derated levels of a generating unit, the operating time at the derated level is transformed into an equivalent outage time.

[37] Derated Adjusted Forced Outage Rate (DAFOR) is a metric that measures the percentage of time that a unit or group of units is unable to generate at its Maximum Continuous Rating (MCR) due to forced outages. The DAFOR for each unit is weighted to reflect differences in generating unit sizes in order to provide a company total and reflect the relative impact a unit's performance has on overall generating performance. This measure is applied to hydraulic and thermal units. However, this measure is not applicable to gas turbines because of their nature as standby units and therefore low operating hours.

[38] Utilization Forced Outage Probability (UFOP) is metric that measures the percentage of time that a unit or group of units will encounter a forced outage and not be available when required. This metric is used for gas turbines.

Thermal Generation Performance

Hydro's thermal generation performance for the period 2012 to 2016 is provided in Table 3-6.

Table 3-6 Thermal Generation Performance – DAFOR

	2012	2013	2014	2015	2016
Thermal DAFOR	5.98	36.58	13.74	5.04	19.42

Hydro's thermal DAFOR performance improved in 2014 and 2015. However, in 2016, Holyrood Units 1 and 2 were derated due to airflow and reheater tube limitations, and Holyrood Unit 3 was derated due to issues with broken generator leads, failed west fuel oil pump, air heater fouling, and fouling on the water intake.

Gas Turbine Performance

Table 3-7 provides the UFOP performance for Hydro's gas turbines for the period 2012 to 2016.

Table 3-7 Gas Turbine Performance to UFOP

	2012	2013	2014	2015	2016
Hardwoods/Stephenville/Happy Valley UFOP	44.21	26.57	14.34	12.13	9.35
Holyrood Gas Turbine UFOP	-	-	-	3.06	1.65

The UFOP for the combined Hardwoods, Stephenville, and Happy Valley gas turbines has been improving since 2012. The gas turbine at Holyrood has been in operation since March 2015. This unit has operated well, with a UFOP well below the CEA average for comparable units.[39]

3.4.5 Safety, Health, and Environment

Ensuring the safety of its employees and the general public is a top priority for Hydro as it continues to take a targeted approach towards injury prevention, communication, and awareness. The Company is focused on educating its employees and contractors about the

[39] The CEA average for 2011 to 2015 is 21.17%.

importance of safety in day-to-day operations, emphasizing management and reduction of work place injuries. Hydro continues to invest in the appropriate tools, training, and equipment to ensure employees are able to do their jobs in a safe and productive manner. Hydro is also committed to the safety of the general public through improved communications. Since 2012, Hydro's All Injury Frequency Rate and Lost Time Frequency Rate have improved. Table 3-8 provides a summary of Hydro's safety performance for the period 2012 to 2016.

Table 3-8 Safety Performance 2012 to 2016

	2012	2013	2014	2015	2016
Lost Time[40]	6	2	0	3	1
Medical Treatment Injuries[41]	11	7	4	7	5
All Injury Frequency Rate[42]	2.25	1.16	0.48	1.16	0.74
Lost Time Injury Frequency Rate[43]	0.79	0.26	0.00	0.35	0.12
Severity Rate[44]	44.53	7.07	0.00	75.96	0.25
Days Lost[45]	337	55	0	656	2
High Potential Incidents[46]	10	9	7	9	10

Hydro's environmental commitment to sustainable practices in its operations is demonstrated throughout the Company's activities. Hydro has integrated initiatives in alternative energy, energy conservation, and community partnerships into its operations throughout the province. Hydro has a responsibility to preserve sensitive habitats and vegetation and makes every effort to ensure minimal environmental impacts through its operations. The Company continues to

[40] Lost Time Injury is a standard safety performance metric and is defined as a work related injury where an employee requires medical attention and is unable to return to work for his/her next scheduled shift.
[41] Medical Treatment Injury is a standard safety performance metric and is defined as a work related injury where an employee requires medical attention; however, he/she is able to return to work for the next scheduled shift.
[42] All Injury Frequency Rate is a standard safety performance metric and is defined as the total number of employee Lost Time Injuries and Medical Treatment Injuries per 200,000 hours worked.
[43] Lost Time Injury Frequency Rate is a standard safety performance metric and is defined as the total number of employee Lost time injuries per 200,000 hours worked.
[44] Severity Rates is a standard safety performance metric and is defined as the number of calendar days lost due to a workplace injury or illness per 200,000 hours worked.
[45] Days Lost is defined as the number of calendar days that an employee is unable to work beyond the day of a workplace injury or illness as recommended by a physician or other health care professional.
[46] High Potential Incident is defined as an undesired event that results in, or has the potential to result in, harm to people, damage to equipment, property, or the environment.

use the ISO 14001 Certified Environment Management Systems which provides a framework for an organization's environmental responsibilities and is an integral component of the organization's business operations and continuous improvement focus.

As part of its commitment to environmental protection, Hydro is committed to reducing its greenhouse gas emissions. In 2016, clean renewable energy supplied approximately 74% of customers' needs on the Island Interconnected System. This was provided as a combination of hydroelectric and wind energy. The purchase of 190,036 megawatt hours (MWh) of clean energy from the island's two wind energy projects in 2016 displaced fuel consumption at Holyrood by 307,500 barrels of oil, representing a reduction of nearly 155,000 tonnes in greenhouse gas emissions. To meet the remaining island interconnected load requirements, and provide for all isolated communities across the province, Hydro's fleet of thermal, gas turbine, and diesel generation was utilized. Holyrood supplied 23% of this remaining load on the Island Interconnected System, which is an increase from 20% in 2015. Hydro's thermal, gas turbine, and diesel plants combined generated 1.5 million tonnes of CO_2 equivalent emissions. Hydro is also working with its customers through its conservation and demand management program.[47] Conservation through this program focuses on reduction in costs, but has an added benefit of reduced production, which reduces CO_2 emissions further.

3.5 System Planning and Meeting Customer Load Requirements

3.5.1 Customer and System Load Forecasts

The 2018 and 2019 Test Year load forecasts for the Island Interconnected System reflect a combination of direct input from the Island Industrial Customers[48] and Newfoundland Power. Hydro's internal analyses for the interconnected and isolated systems were prepared over the course of 2016. Total load requirements are determined from analyses of overall system losses, station service, and demand diversity.

[47] The Conservation and Demand Management program is further discussed in Chapter 2: Customers.
[48] This includes Vale Newfoundland and Labrador Limited (Vale), North Atlantic Refining Limited (NARL), Corner Brook Pulp and Paper Limited (CBPP), Teck Resources Limited (Teck), and Praxair Canada Inc. (Praxair).

Island Interconnected System Load Forecast

The 2015 Test Year load forecast, along with the actual power and energy requirements from Hydro for the Island Interconnected System for 2015 and 2016, and the operating load forecasts for 2017 and for the 2018 and 2019 Test Years, are provided in Schedule 3-I.

In 2016, electricity requirements on the Island Interconnected System declined by 2.7% relative to the 2015 Test Year, primarily due to less industrial customer consumption. The lower industrial consumption resulted from lower requirements by Vale as well as lower consumption by Teck due to the closure of its Duck Pond mine near Red Indian Lake. The change in consumption by Newfoundland Power reflects lower overall energy requirements on the Newfoundland Power system that were impacted by warmer than normal weather during 2016. Hydro also incurred lower losses on the bulk transmission system, impacted by the reduced energy requirements and higher thermal production than forecast for the 2015 Test Year. Increased consumption by Hydro Rural Interconnected customers resulted from increased domestic customer consumption and higher general service customer sales.

For 2017, Hydro is forecasting electricity requirements to increase relative to 2016. This reflects higher Island Industrial Customer load mainly driven by increases at Vale's nickel processing facilities and increased requirements by NARL. It is currently anticipated that Vale will continue to increase its levels of demand and energy consumption through 2017 until it reaches full production levels near the end of the year. Increased energy requirements at NARL are associated with higher production levels and resulting higher power demands. Teck's energy requirement is forecast to decline as mine site infrastructure is removed and reclamation work continues. The overall higher industrial load in 2017 is partially offset by lower Newfoundland Power and Hydro Rural requirements that mirror expected provincial economic conditions.

For the 2018 Test Year, Hydro is forecasting an increase in load requirements, relative to 2017. The growth is due to increased requirements forecast for Vale and Praxair upon attaining full load levels at the end of 2017, which more than offset lower requirements forecast for Hydro's other customers including CBPP, NARL, Teck, and Hydro Rural. CBPP requirements are forecast to be lower resulting from expected mill efficiency gains. In the 2018 Test Year, forecast power and energy for Teck reflects continued mine site reclamation and environmental protection requirements. Load requirements forecast by Newfoundland Power remain stable through the 2018 Test Year.

Hydro is forecasting a modest increase in load for the 2019 Test Year relative to the 2018 Test Year. Changes are due to increased requirements for the Island Industrial Customers and by Newfoundland Power which offset a decreased Hydro Rural requirement. The changes to Island Industrial Customer load for the 2019 Test Year reflect increased production days at NARL, and increased energy requirements offset by efficiency gains at CBPP.

Customer peak demand requirements exhibit the same general pattern as energy requirements. Utility requirements remain relatively stable with increased industrial peak demands stemming from nickel processing at Vale reaching full load requirements during the forecast period. Forecast peak demand requirements for Newfoundland Power and Hydro Rural are weather normalized to reflect expected annual requirements for Hydro operations.

Table 3-9 summarizes the overall forecast percentage changes for the Island Interconnected System for the 2018 Test Year in comparison to the 2015 Test Year, and for the 2019 Test Year to the 2018 Test Year.

Table 3-9 Summary of Percentage Change in Hydro's Electricity Requirements (2015 TY to 2019 TY) Island Interconnected System (GWh)

	2015 TY	Percentage change from 2015 TY to 2018 TY	2018 TY	Percentage change from 2018 TY to 2019 TY	2019 TY
Newfoundland Power	5,924.1	-1.7%	5824.5	0.2%	5,833.6
Island Industrial Customers	621.4	16.8%	726.0	2.4%	743.3
Hydro Rural Interconnected	463.9	-1.5%	457.0	-1.2%	451.5
Losses	225.7	-4.7%	215.0	-3.8%	206.9
Total Hydro Island Interconnected Electricity Requirements	**7,235.1**	**-0.2%**	**7222.5**	**0.2%**	**7,235.3**

Labrador Interconnected System Load Forecast

The 2015 Test Year load forecast, the actual power and energy supplied to the Labrador Interconnected System by Hydro for 2015 and 2016, and the operating load forecasts for 2017 and for the 2018 and 2019 Test Years, are provided in Schedule 3-II.

Hydro's overall electricity supply for the Labrador Interconnected System in 2016 declined by 5.4% relative to the 2015 Test Year with reduced energy requirements associated with lower sales to both Industrial Customers and Hydro Rural customers. Lower losses incurred on the bulk transmission system and near zero secondary energy sales to CFB Goose Bay were contributing factors. The temporary closure of Wabush Mines, as announced in the Fall of 2014, resulted in reduced industrial energy requirements. The reduction was partially offset by higher requirements for the Iron Ore Company of Canada (IOC). The change in consumption by Hydro Rural customers reflects lower energy requirements at Nalcor Energy's construction site at Muskrat Falls as well as reduced energy requirements in the communities of Labrador City and Wabush.

For 2017, Hydro is forecasting slightly increased electricity requirements relative to 2016. This primarily reflects increased sales for Hydro's Rural customers that offsets a minor reduction in industrial customer sales. Forecast higher rural customer sales are mainly driven by new data centre loads. The forecast industrial sales primarily reflects energy required based on an average of multi-year production levels for IOC while no secondary sales to CFB Goose Bay are forecast.

For the 2018 Test Year, Hydro is forecasting minor changes in Hydro Rural load reflecting forecast increases in data centre load requirements in the Western Labrador region. No secondary energy requirements at CFB Goose Bay are forecast and the change in industrial load is due to lower energy requirements forecasted for Wabush Mines.[49]

[49] In June 2017, it was announced that the new owner of Wabush Mines intends to reopen the site. Hydro is monitoring the situation closely and is in discussions with Tacora Resources about their potential needs.

In the 2019 Test Year, reclamation activities requiring energy are forecast to be concluded at Wabush Mines and there is little or no change to forecast energy requirements for either Hydro Rural or CFB Goose Bay secondary sales relative to the 2018 Test Year. Forecast load requirements for Hydro Rural customers for the 2019 Test Year reflect increased data centre loads and reduced loads at the Muskrat Falls construction site.

Table 3-10 summarizes the overall forecast percentage changes for the Labrador Interconnected System for the 2018 Test Year in comparison to the 2015 Test Year, and for the 2019 Test Year to the 2018 Test Year.[50]

Table 3-10 Summary of Percentage Change of Hydro's Electricity Requirements (2015 TY to 2019 TY) Labrador Interconnected System (GWh)

	2015 TY	Percentage change from 2015 TY to 2018 TY	2018 TY	Percentage change from 2018 TY to 2019 TY	2019 TY
Hydro Rural Customers	688.1	0.1%	688.6	0.0%	688.5
Industrial Customers	1,790.0	-3.1%	1,734.3	-0.1%	1,733.1
CFB Goose Bay Secondary	10.2	-99.6%	< 0.0	< 0.0%	< 0.0
Losses	188.6	-19.9%	151.1	-0.1%	150.9
Total Hydro Labrador Interconnected Electricity Requirements	2,676.9	-3.8%	2,574.0	-0.1%	2572.5

Isolated System Load Forecasts

The 2017 to 2019 system load forecasts were prepared using Hydro's internal load forecast analysis.

The 2015 Test Year load forecast, the actual power and energy requirements for Hydro's isolated systems for 2015 and 2016, and the operating load forecasts for 2017 and for the 2018 and 2019 Test Years are provided in Schedule 3-III.

[50] Schedule 3-II and Table 3-10 present the actual and forecast total industrial energy requirements. Prior Hydro rate applications provided the industrial energy requirements from Labrador recall power only and did not include energy volumes supplied by TwinCo.

Electricity requirements across the combined Labrador Isolated systems and L'Anse au Loup system was higher in 2016 relative to the 2015 Test Year. Hydro's load forecast for the combined systems reflects overall increased requirements for the L'Anse au Loup system as well as for the other Labrador Isolated Systems. Load increases are forecasted, in part due to increased requirements in the L'Anse au Loup system caused by the continued growth of electric heat use by residential customers. The forecast growth in the Labrador Isolated Systems is primarily in Nunatsiavut communities, located on the North coast of Labrador, reflecting infrastructure investments and some penetration of electric heat.

The forecasts for the Island Isolated Systems for 2017 through to the 2019 Test Year reflect a continued slow decline in the Island Isolated communities.

Table 3-11 summarizes the overall percentage forecast changes for Hydro's Isolated Systems for the 2018 Test Year in comparison to the 2015 Test Year, and for the 2018 Test Year to the 2019 Test Year. The L'Anse au Loup forecast has been provided separate from the Labrador Isolated Systems, given the uniqueness of supply for that region.

Table 3-11 Summary of Percentage Change in Hydro's Electricity Requirements (2015 TY to 2019 TY) Isolated Systems (MWh)

	2015 TY	Percentage change from 2015 TY to 2018 TY	2018 TY	Percentage change from 2018 TY to 2019 TY	2019 TY
L'Anse au Loup	25.0	7.4%	26.8	0.7%	27.0
Labrador Isolated Systems[51]	44.9	2.7%	46.1	0.4%	46.3
Island Isolated Systems	7.6	-1.3%	7.5	-0.4%	7.5
Total Isolated Systems	77.5	3.8%	80.5	0.5%	80.8

3.5.2 Sources of Supply

Island Interconnected System

Simulations for this GRA were completed using all available hydrology from 1950 to 2015, inclusive, 66 years in total. Hydro continues to model the Island Interconnected System in Vista

[51] Excludes L'Anse au Loup System.

DSS (Vista). Currently, Hydro uses seven-day hourly precipitation and temperature forecasts to produce inflow forecasts for use in hourly modeling.

Hydraulic Generation

Hydro has undertaken significant effort to further develop its Vista model to more accurately represent the changing Newfoundland and Labrador electricity system. The revised model of the Island Interconnected System was used to estimate the usage of various energy sources to meet the island system load. This section describes the methodology used by Hydro to estimate its average annual hydraulic energy production in the 2018 and 2019 Test Years.

Inflows to each of Hydro's reservoirs are calculated daily from measured water levels and estimated outflows. At the end of each year, Hydro reviews the calculated inflows and makes any necessary adjustments. Such adjustments include:

- smoothing to remove calculated negative inflows, a common problem when back calculating inflows from water level changes; and
- adjustments to the distribution of inflows between two reservoirs when the estimates of flow in the connecting canals are not well known.

Hydraulic Production Forecast

The hydraulic production forecast determined from the Vista model for the 2018 Test Year is 4,601 GWh, increasing slightly to 4,606 GWh in the 2019 Test Year. These hydraulic production forecasts are consistent with those used in the 2015 Test Year of 4,604 GWh. It should be noted that Exploits Generation is not included in this projection of hydraulic production, as Exploits Generation continues to form part of Hydro's Power Purchases, as detailed below.

Hydro's sources of supply are detailed in the production plan (referred to as the hydro-thermal split) and are included in Schedule 3-IV. The actual energy supply sources and fuel expenses for 2015, 2016, and the forecast for 2017 through to the 2019 Test Year are summarized in Schedule 3-V.

Losses

The enhanced Island Interconnected System Vista model has a more detailed representation of Hydro's transmission system. The model calculates losses based on the flow of energy between areas of Hydro's system, using dynamic loss equations. This allows losses to be modelled more accurately than in Hydro's previous rate filings. As such, losses included in the Island Interconnected System have been forecast using Hydro's Vista model.

<u>Power Purchases</u>

The 2015 Test Year power purchase forecast, along with Hydro's actual power purchases for the Island Interconnected System for 2015 and 2016, and the forecast power purchase requirements for 2017 and for the 2018 and 2019 Test Years are provided in Schedule 3-VI. Table 3-12 represents the annual changes in Hydro's purchase power requirements for that period.

Table 3-12 Summary of Percentage Change in Power Purchases (2015 TY to 2019 TY) Island Interconnected System (GWh)

	2015 TY	Percentage change from 2015 TY to 2018 TY	2018 TY	Percentage change from 2018 TY to 2019 TY	2019 TY
Exploits	633.5	-2.9%	615.1	0%	614.9
Star Lake	142.2	-0.9%	140.9	0.8%	142.0
Rattle Brook	15.0	-1.1%	14.8	-	14.8
CBPP Co-Gen	51.1	30.3%	66.5	-	66.5
CBPP Secondary	-	-	-	-	-
St. Lawrence Wind	104.8	-	104.8	-	104.8
Fermeuse Wind	84.4	-	84.4	-	84.4
Total Purchases	1031.0	-0.4%	1026.5	0.1%	1027.4

Exploits and Star Lake Generation

The total forecast generation included for the Exploits generation facilities in 2017 is 587 GWh. The total forecast generation included for the Exploits generation facilities is 615 GWh for both the 2018 and 2019 Test Year. The lower volume of power purchases in 2016 and 2017 is primarily due to reservoir conditions, inflows, unanticipated plant outages (e.g., the flooding of the Bishop's Falls powerhouse during Hurricane Matthew in 2016), and planned upgrades. Total forecast generation for the Nalcor Star Lake facilities is 140.3 GWh in 2017, 140.9 GWh in the 2018 Test Year, and 142.0 GWh in the 2019 Test Year.

Non-Utility Generators (NUGS)

Deer Lake Power's plant on Grand Lake is included in Hydro's Vista model and is modeled to a level of detail similar to that of Hydro's own system. Hydro has no forecast energy requirement from this plant.

CBPP Co-Generation

For 2017 and both the 2018 Test Year and 2019 Test Year, forecast production from the co-generation facilities is constant at 66.5 GWh.

Wind Generation

On the Island Interconnected System, wind energy has been generated at St. Lawrence since October 2008 and at Fermeuse since April 2009. Power Purchase Agreements (PPA) exist with NeWind Group Inc. for the St. Lawrence wind energy and with Elemental Energy for the Fermeuse wind energy. At each site, there are nine 3 MW wind turbines, for a total Island Interconnected System installed capacity of 54 MW. In 2016, the total Island Interconnected wind generation purchased was nearly 190 GWh. Estimates of generation from each wind farm are included in the Vista model as purchase contracts.

Newfoundland Power and Small Hydro Sites

Newfoundland Power's sites are modeled in Hydro's Vista analysis as one pseudo site with characteristics and input hydrology that result in a reasonable estimate of its generation. Several other small plants (Snook's Arm, Venam's Bight, Rattle Brook, and Roddickton mini-hydro) are included with Newfoundland Power's sites as they are too small to warrant modelling separately and have similar characteristics to Newfoundland Power's sites.

Newfoundland Power Generation Credit

Newfoundland Power's generation credit is calculated based on the Island Interconnected System's reserve at criteria. Reserve at criteria is not the same as system reserve. To calculate the reserve at criteria, the 240 MW[52] reserve margin is subtracted from the total Island Interconnected System capacity at peak, inclusive of capacity assistance contracts, to determine the maximum Island Interconnected System demand that can be supported on peak. This maximum demand that can be supported on peak is then used to calculate the percent reserve at criteria.

In the 2015 Test Year, the reserve at criteria was 13.3%, which resulted in a total generation credit for Newfoundland Power of 119.3 MW. The reserve at criteria of the Island Interconnected System has been slightly reduced to 12.8% for the 2018 and 2019 Test Years. When applied to Newfoundland Power's revised generation capability forecast for the 2018 Test Year and the 2019 Test Year, the generation credit becomes 118.1 MW, representing a 1 MW reduction in credit. The calculation of Newfoundland Power's generation credit is shown in Table 3-13.

Table 3-13 Newfoundland Power Generation Credit (kW)

Hydraulic Capacity	94,191
Thermal Capacity	39,000
Total	**133,191**
Reserve at Criteria	1.128225
Newfoundland Power Generation Credit	**118,054**

Holyrood Thermal Generation

Hydro's customer and system requirements in excess of that which can be met by Hydro's hydraulic assets, under average hydrological conditions, and Hydro's existing purchase

[52] To ensure reliable system operation in covering the single worst contingency, Hydro targets a spinning reserve equal to the capacity of the largest online unit. For the current system, this is equal to 170 MW when Unit 1 or 2 at Holyrood is online, and is otherwise 154 MW, which is the capacity of Bay d'Espoir Unit 7. Hydro maintains an additional 70 MW of available reserve above these spinning reserve requirements. This reserve, over and above what is required for the single worst contingency, covers performance uncertainties in generating units, especially wind and other variable generation, transmission equipment and unanticipated increases in demand. This assists in expediting load recovery for a large generation loss, and is required for prudent management of system risks for customers.

contracts have been assumed to be met with thermal generation from Holyrood and standby generation from Hydro's gas turbine facilities.

Based on this premise, Holyrood actual and forecast production is summarized in Table 3-14. Changes from the 2015 Test Year are due to variances in load, hydraulic production, and power purchases.

Table 3-14 Summary of Year-Over-Year Changes in Holyrood Thermal Generating Station Requirements (GWh)

	2015 TY	2015 Actual	2016 Actual	2017 Forecast	2018 TY	2019 TY
Thermal Generation Required	1,593	1,543	1,707	1,521	1,554	1,560
Change over previous year	N/A	(50)	164	(186)	33	6

The actual and forecast fuel conversion factors are summarized in Table 3-15. For the 2018 and 2019 Test Years, the forecast conversion factor of 616 kWh/bbl is slightly lower than the current Board-approved conversion factor of 618 kWh/bbl. The monthly No. 6 Fuel Purchase Prices for 2015 to 2019 are included as Schedule 3-VII.

Hydro forecasts the Holyrood conversion factor using a five-year regression analysis of conversion factor versus Holyrood gross monthly average unit loading, adjusted for fuel heating content (in BTUs/bbl). There is a station service factor of 6.2% applied to the gross energy production. The station service factor is based on the average experience over the five year period from January 2011 through December 2015.

Table 3-15 Summary of Year-Over-Year Changes in Holyrood Thermal Generating Station Conversion Factor (KWh/bbl)

	2015 Board Approved Conversion Factor	2015 Actual	2016 Actual	2017 Forecast	2018 TY	2019 TY
Conversion Factor	618	602	608	603	616	616
Change over previous year	N/A	(16)	6	(5)	13	-

Island Interconnected System Gas Turbine and Diesel Generation

For the winter periods of 2017/2018 and 2018/2019, there are peaking requirements assumed for the Island Interconnected System gas turbines in order to maintain minimum generation reserve requirements. The requirements for the gas turbines are determined in consideration of thermal and hydraulic forced outage rates, and in consideration of the peak load forecast and Hydro's typical load duration curve.

The Island Interconnected System gas turbines and diesel production also assumes that each plant is exercised at rated output for one hour per month during the non-winter period for testing and for ensuring availability. These units are assumed to be exercised for four hours during each winter month (approximately once per week) for winter readiness and storm preparedness. Table 3-16 provides the Forecast for Hydro's Gas Turbine and Diesel production.

Table 3-16 Forecast Gas Turbine and Diesel Production (GWh)

	2015 TY	2015 Actual	2016 Actual	2017 Forecast	2018 TY	2019 TY
Forecast Production	11	41	120	57	41	41

Higher unavailability at Holyrood and changes in Hydro's operating parameters, where units have been dispatched as mitigating measures to avoid potential customer disruption, resulted in increased production in 2015 and 2016 in comparison to the 2015 Test Year. The reduced production forecast for Hydro's Island Interconnected System gas turbines and diesels for 2017 through to the 2019 Test Year reflect the reliability benefit of the planned in service of a third transmission line from Bay d'Espoir to Western Avalon (TL267).

Capacity Assistance Agreements

Hydro presently has five capacity assistance[53] agreements in place with its Industrial Customers: two with Corner Brook Pulp and Paper, two with Vale, and one with Praxair.[54]

[53] Capacity assistance can be provided in two ways. The first is by a customer providing additional generation capacity to Hydro. This is the case in both Corner Brook Pulp and Paper Capacity Agreement, with the exception of

In addition to the capacity assistance agreements, Hydro provides a curtailable credit to Newfoundland Power which was approved by the Board in Order No. P.U. 47(2014). The amount of Newfoundland Power curtailable load available is forecast to be 11 MW for 2017 and for the 2018 and 2019 Test Years.

Labrador Interconnected System

The majority of all energy consumed on the Labrador Interconnected System is purchased from Churchill Falls (Labrador) Co. (CF(L)Co). The only additional source of supply is the gas turbine and diesel generation in Happy Valley-Goose Bay which can be operated for Labrador Interconnected System outages or system support.

<u>*Power Purchases*</u>

The energy supplied from CF(L)Co is supplied from two distinct blocks: the Recapture Block and the Twin Falls Power Corporation (TwinCo) Block.[55] The Recapture Block provides Hydro with up to 300 MW from CF(L)Co for use outside the province of Quebec. Hydro currently uses a portion of the Recapture Energy to supply its customers in Labrador.

The TwinCo Block of power is a firm 225 MW block of power and energy, capable of supplying 1,971 GWh per year. It is currently resold by Hydro for industrial operations in Labrador West and is included in the Development Block in the Labrador Industrial Rates.

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the first 9 MW, and the Vale Capacity Assistance Agreement. The second way a customer can provide capacity assistance is by curtailing its load and reducing the overall system demand. This is the case for the first 9 MW of the Corner Brook Pulp and Paper Capacity Assistance Agreement, the Praxair Load Curtailment Agreement, and the Vale Load Curtailment Agreement.

[54] A description and summary of the capacity assistance agreements currently in place can be found in Hydro's Capacity Assistance Report 2016-2017, filed with the Board on April 17, 2017.

[55] On May 12, 1969, Hydro-Quebec (HQ) and CF(L)Co entered into a power contract for the purchase of power from the CF(L)Co plant by HQ (the 1969 Power Contract). Pursuant to section 6.6 of the 1969 Power Contract, CF(L)Co has exercised its right to recapture 300 MW of power (Recapture Energy) generated at the CF power plant. Under the terms of a PPA between Hydro and CF(L)Co (the NLH-CF(L)Co PPA) dated March 9, 1998, and amended on April 1, 1999, Hydro is able to, and does, purchase up to 300 MW of Recapture Energy from CF(L)Co for use outside of the Province of Quebec.

Under the terms of the HQ-Hydro Shareholders Agreement governing the operation of the Churchill Falls plant, CF(L)Co must make a firm 225 MW block of power and energy (the TwinCo Block) available to Hydro for distribution and use in Labrador West.

The TwinCo Block has been available to Hydro since the end of 2014, when pre-existing contracts between CF(L)Co and TwinCo expired.

Isolated Systems

The primary source of power supply for Hydro's isolated systems throughout the province is diesel generation. Hydro continues to avail of opportunities to supplement or displace diesel generation. On the L'Anse au Loup system, Hydro displaces diesel generated energy by purchasing secondary energy from a regional Hydro-Québec hydroelectric plant. On the Ramea diesel system, Hydro continues to purchase wind energy through its contracts with Frontier Power and Nalcor Energy.

Diesel Generation

Hydro owns and operates diesel generating facilities in its isolated systems. The actual diesel fuel expenses for 2015 and 2016 and the forecast fuel requirements for 2017 through to the 2019 Test Year are summarized in Schedule 3-VIII.

Power Purchases

Hydro has a power purchase agreement with Frontier Power for wind generation at Ramea. Frontier Power has six 65 kW wind turbines installed for a total capacity of 390 kW. Additionally, Hydro is anticipating wind generation from the Ramea Wind-Hydrogen-Diesel facility.[56] Hydro is forecasting 690 MWh of production in both the 2018 Test Year and the 2019 Test Year from these facilities. This energy will help to offset diesel fuel usage and result in a further displacement of greenhouse gas emissions.

3.5.3 Adequacy of Supply

In order to ensure that the future capacity and energy requirements of the Island Interconnected System are met in a reliable and cost effective manner, Hydro regularly

[56] The Ramea Wind-Hydrogen-Diesel facility is a research and development project. The construction and installation of the wind-hydrogen-diesel system was approved in Order No. P.U. 31(2007). While operations and maintenance work on this facility is performed by Hydro, all charges are incurred by Nalcor.

prepares long term forecasts for the provincial power system and maintains a portfolio of projects with various levels of engineering feasibility assessment.

Transmission Planning Criteria

The provincial transmission system is assessed and expanded based upon prescribed transmission planning criteria. The transmission planning criteria used by Hydro, and reviewed by the Board, are defined as follows:

1. In the event a transmission element is out of service (i.e., under contingent or n-1 operation), power flow in all other elements of the power system should be at or below normal rating;
2. For normal operations, the system is planned on the basis that all voltages be maintained between 95% and 105% of nominal voltage; and
3. For contingency or emergency situations, voltages between 90% and 110% of nominal voltage are considered acceptable.

Hydro is currently constructing a new 230 kV transmission line between Bay d'Espoir and the Avalon Peninsula (TL267). This project will enable the delivery of additional capacity to the Avalon Peninsula, relieve congestion, reduce system losses, enhance the resiliency of the current transmission network originally built in the late 1960s, and reinforce the future interconnection of the island system with the North American grid. The project is anticipated to be completed, and in service with the ability to bring additional power to the Avalon Peninsula for winter 2017/2018.[57]

The transmission system in Western Labrador was constructed in the 1960's and has seen minimal capital investment during its life span and has exceeded its original design capacity

[57] A serious incident on June 19, 2017, resulted in the fatality of two contractor employees. An investigation is currently being carried out by Occupational Health and Safety. At the time of filing, all guyed tower activities have been suspended; however, other ground activities and station work are continuing to resume in a phased approach. Hydro is currently assessing the impact the incident will have on the in-service date.

carrying requirements. Continued load growth in the region will require substantial capital investment to meet an acceptable level of reliability.

In its 2018 Capital Budget Application, Hydro is seeking approval of a single-year project to build an additional transmission line to the Happy Valley Terminal Station. This project, scheduled for completion in the fall of 2018, will alleviate the current transmission constraint in the Labrador East Interconnected area.[58]

Generation Planning Criteria

<u>*Island Interconnected System*</u>

Hydro has established generation planning criteria for the Island Interconnected System that determines the timing of generation source additions to meet customer demand.[59] These criteria set the minimum level of capacity and energy installed on the Island Interconnected System to ensure an adequate supply for firm demand.[60] Hydro's generation planning criteria are as follows:

> **Capacity:** The Island Interconnected System should have sufficient generating capacity to satisfy a Loss of Load Hours (LOLH) expectation target of not more than 2.8 hours per year.[61]
>
> **Energy:** The Island Interconnected System should have sufficient generating capability to supply all of its firm energy requirements with firm system energy capability.[62]

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[58] The estimated cost of this project is approximately $24 million.

[59] In 2017, Hydro conducted an analysis of its ability to supply its customers in advance of Muskrat Falls commissioning. Hydro concluded that there is no requirement for additional supply on the Island Interconnected System in advance of Muskrat Falls commissioning. Please refer to Hydro's *Near-Term Generation Adequacy Report*, filed with the Board on May 15, 2017.

[60] Hydro's generation planning criteria have been in use for more than 35 years and in that period have been reviewed several times, most recently by Manitoba Hydro Incorporated, Ventyx, and Liberty Consulting.

[61] LOLH is a statistical assessment of the risk that the System will not be capable of serving the System's firm load for all hours of the year. For Hydro, an LOLH expectation target of not more than 2.8 hours per year represents the inability to serve all firm load for no more than 2.8 hours in a given year.

[62] Firm capability for the hydroelectric resources is the firm energy capability of those resources under the most adverse three-year sequence of reservoir inflows occurring within the historical record. Firm capability for the thermal resources (Holyrood Thermal Generating Station) is based on energy capability adjusted for maintenance and forced outages.

Additionally, Hydro now maintains a megawatt reserve greater than 240 MW on the Island Interconnected System.[63] This 240 MW reserve margin provides Hydro with the ability to withstand the most onerous single contingency (loss of the Holyrood Unit 1 or 2) while maintaining a spinning reserve of 70 MW.

Labrador Interconnected System

To ensure that capacity and energy requirements are met on the Labrador Interconnected System, Hydro compares the Labrador Interconnected System requirements with the 300 MW block of Recapture power and associated energy and the 225 MW block of TwinCo power, all available from CF(L)Co.

Isolated Systems

Hydro has established generation and distribution planning criteria for its Isolated Rural Systems to ensure its ability to meet customer requirements. Hydro's generation planning criteria for its isolated systems is as follows:

Capacity: Hydro shall maintain firm generation capacity to meet the system peak load.[64]

Energy:

For isolated locations where Hydro maintains long-term bulk fuel storage:

- Island Systems - sufficient fuel shall be stored on site, such that the energy requirements of the system can be met for four consecutive months.
- Labrador Systems - sufficient fuel shall be stored on site, such that the energy requirements of the system can be met for nine consecutive months.

[63]This operational change aligns with recommendations made by Liberty as part of the Board's *Investigation and Hearing into Supply Issues and Power Outages on the Island Interconnected System – Phase One.* Please refer to *Report to the Board of Commissioners of Public Utilities – Review Supply Issues and Power Outages Island Interconnected System, December 17, 2014*, filed with Board on March 31, 2017.

[64] Firm generation capacity is defined as the total installed capacity on the system not including non-firm energy sources as noted above minus the largest single unit. This means that Hydro's firm capacity planning criteria in isolated systems covers a first contingency (i.e., n-1) situation.

For locations where a local vendor is used to supply fuel in lieu of on-site storage:

- The fuel vendor must have enough storage to meet Hydro's winter fuel requirements. Hydro's fuel requirements are communicated to the vendor in the fall before the final fuel delivery.

Capacity for Hydro's Rural Isolated Systems is provided by diesel generating plants which house a number of diesel generator sets (Gensets). The minimum number of units in a diesel plant is three, and typical plant size is from three to four units, although some (typically larger) plants contain more units. The firm power rating of the generating unit is used to state the capacity.[65] Hydro uses the prime power rating for the firm capacity of the diesel units used in the rural isolated diesel plants.[66] Gensets are assumed to be capable of achieving their respective nameplate ratings throughout their lifecycle.

Energy for Hydro's Rural Isolated Systems is provided from either Type A (Arctic Grade) or Type B Diesel Fuel supplied by a local fuel vendor or stored on site by Hydro. Hydro ensures sufficient fuel is available to supply energy requirements of the system over the winter period when fuel deliveries to the site are unavailable.

3.6 Rural Deficit

Revenues from Hydro's Rural Customers, with the exception of those on the Labrador Interconnected System, do not fully recover the costs to serve those customers, resulting in a deficit in Hydro's revenue (the Rural Deficit). The Rural Deficit has grown from $59.4 million as approved in the 2015 Test Year to a forecast of $68.1 million in the 2018 Test Year and $73.2 million in the 2019 Test Year, primarily due to increased operating and maintenance costs, fuel costs, and power purchases, as well as return.

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[65] Firm power rating means the amount of capacity that can be reasonably guaranteed from a generating unit at a particular instant when required. In the case of capacity planning, it describes the capacity that can be expected from a generating unit during the system peak load.
[66] Output available with varying load for an unlimited time. Average power output is 70 percent of the prime power rating.

One aspect in managing the Rural Deficit is to keep the cost of operating and maintaining the rural systems at least cost while also carrying out Hydro's obligation to provide safe and reliable service. Hydro strives to determine and implement the least-cost alternatives to keep the rural systems operating within criteria.[67]

Hydro seeks to reduce the cost of providing service to its rural customers. One such initiative is to encourage reduction in energy usage by customers through its Conservation and Demand Management Program initiatives.[68] Other initiatives include:

- Connecting isolated rural systems to the interconnected grid, when economically feasible. Over 60 systems have been interconnected in the past 50 years and Hydro continues to look for cost effective opportunities to interconnect the remaining isolated rural systems.[69]
- Alternative sources of supply. Hydro continues to look for more cost-effective sources of supply. For example, in 1995, Hydro signed a share-the-savings contract with Hydro Quebec (HQ) to supply the L'Anse au Loup system with surplus hydroelectric power from Quebec's Lower North Shore system at 50 percent of the cost of diesel. Typically, greater than 90 percent of the power on the L'Anse au Loup system is supplied from HQ. This contract ends in 2020 and Hydro plans to enter into renegotiations with HQ. Hydro is also in discussions with the proponents of the Mary's Harbour facility in Mary's Harbour to purchase energy from their hydroelectric plant to supply the Mary's Harbour system. Hydro supports the provincial government in exploring alternative sources, such as small wind and solar. Hydro also meets with vendors proposing alternative energy sources for rural areas and acknowledges that constructing and operating these projects cost-effectively and reliably in remote areas is challenging.
- Internal Energy Efficiency Initiatives. Hydro targets internal energy usage reductions in all facilities, including diesel plants, offices, and line depots. This includes installing

[67] For example, if the conductor on a distribution line needs to be replaced, once technical criteria are satisfied, Hydro will analyze using an even larger conductor to further reduce power losses. If the cost of the power savings from losses exceeds the additional cost of installing a larger conductor, then that alternative will be put forward.
[68] Further information regarding Hydro's Conservation and Demand Programs is located in Chapter 2: Customers.
[69] Some of these systems were first amalgamated into one diesel system, and then interconnected when feasible.

energy efficient lighting at the St. Brendan's, L'Anse au Loup, and Postville diesel plants and capturing waste heat in Hydro's diesels plants to heat Hydro premises. Hydro continues to perform life cycle cost analysis to ensure overall least cost options are chosen when analyzing new tenders for the purchase of new diesel engines. Hydro also monitors diesel system fuel efficiency to identify poor performers so that corrective action may be taken.

- LED Street Light Replacement. In 2015, Hydro commenced a pilot project to install LED streetlights in Nain. This project is anticipated to yield fuel savings due to lower energy requirements compared to high pressure sodium lights. Hydro anticipates expanding the use of LED street lights across its rural systems.
- Hydro is a member of the Canadian Off-Grid Utilities Association (COGUA). This is an association of utilities in Canada that have communities not connected to the grid. This offers opportunities to share information about initiatives that other utilities have tried, what works, and pitfalls to avoid.

Environmental regulations are becoming more stringent. The Federal government is in the process of introducing a tax on carbon. This will increase the cost of fuel on the isolated diesel systems and thus raise the cost of supplying power. Regulations on nitrogen oxide emissions are becoming more stringent. Complying with these regulations may mean increased costs for diesel units and fuel as well as a reduction in fuel efficiency.

Hydro will continue to undertake initiatives to manage the costs of serving its Rural Customers in a manner that is consistent with providing reliable service and meeting its environmental obligations.

3.7 2018 and 2019 Operating and Capital Costs

3.7.1 Operating Costs – General

Hydro's operating costs category represents approximately 21% of each of Hydro's 2018 and 2019 Test Year revenue requirements.

Table 3-17 provides Hydro's operating costs from the 2015 Test Year to 2019 Test Year.[70]

Table 3-17 Hydro's Operating Costs 2015 TY to 2019 TY ($000s)

2015 TY	2015 GRA Order	2015 Approved TY	2015 Actual	2016 Actual	2017 Forecast	2018 TY	2019 TY
139,569	(6,832)	132,737	150,921	123,912	134,341	142,377	145,333

Hydro's approved 2015 Test Year operating costs was $132.7 million, which included a disallowance of $6.8 million. As noted in Figure 3-2, using Hydro's 2015 Test Year (as submitted), forecast operating costs escalated using inflation would be $148.5 million[71] in the 2019 Test Year.

Hydro's 2019 Test Year forecast is $145.3 million, which reflects Hydro's renewed focus and commitment to cost control.[72]

[70] An overview of costs by Functional Area and by Cost Type is contained in Schedules 3-IX and 3-X, respectively.
[71] Inflation over the period from 2015 to 2019 is 6.4%, or 1.6 % per year.
[72] Hydro's actual operating costs in 2015 were $150.9 million, an increase of $11.3 million over Hydro's 2015 Test Year as submitted in its 2013 Amended GRA. These costs were primarily driven by labour cost increases of $1.7 million and maintenance related costs of $5.1 million due to work effort associated with maintenance back log catch up activity. During this time, Hydro was involved in the 2013 Amended GRA, which resulted in increased consulting and related costs as well as costs related to the supply outage investigation, which resulted in an additional $4.5 million of costs.

In 2016, Hydro's operating costs were $15.7 million less than Hydro's 2015 Test Year costs as submitted in the 2013 Amended GRA. This was achieved through targeted reductions and efficiency opportunities, including some temporary deferral of costs. In 2016, cost reductions in labour of $7.5 million were achieved due to changes in FTEs, changes in actuarial assumptions that are used to derive the costs of employee future benefits, as well as higher capitalization. During 2016, Hydro temporarily deferred or limited various operating activities without compromising safety and reliability, which resulted in cost decreases of $5.3 million. These cost deferrals were not sustainable and did not reflect normalized operating cost levels. In 2017, operating costs return to normalized levels.

In 2016, a plan to reorganize Hydro was announced which resulted in the creation of a dedicated and separate executive team for Hydro and established separate support functions for Hydro. Hydro's 2017 Forecast operating costs reflect the outcome of these changes. Operating costs in 2017 are forecast to be $10.4 million higher than 2016 actual costs. The primary drivers of the increase are labour costs of $4.0 million, other operating costs of $3.3 million, including consulting, insurance, and other costs, as well as an increase of $2.4 million in cost allocations associated with Information Systems and other costs.

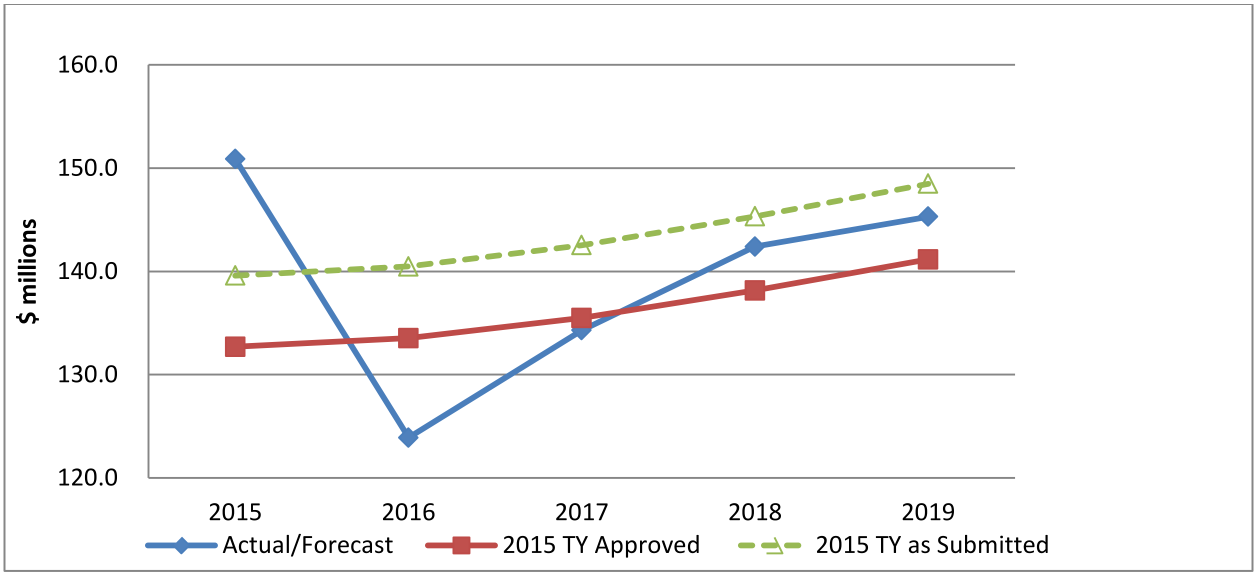

Figure 3-2 Hydro's Operating Costs Escalated for Inflation 2015 to 2019

3.7.2 Operating Costs - 2018 and 2019 Test Years

Hydro classifies its operating costs by Cost Type and by Functional Area. For example, the salary costs of a line worker in Transmission and Rural Operations would be classified in two ways: (i) by Function, as a Transmission and Rural Operations cost in Operations; and (ii) by Cost Type, as a Labour cost.

Operating Costs by Cost Type

The primary categories for Hydro's Operating Costs are Labour, System Equipment and Maintenance (SEM) and Cost Allocations.

Table 3-18 provides the breakdown of Hydro's operating costs from the 2015 Test Year, as submitted, to the 2019 Test Year.

Table 3-18 Operating Costs by Cost Type 2015 TY to 2019 TY ($000s)

Cost Type	2015 TY	2015 GRA Order	2015 Approved TY	2015 Actual	2016 Actual	2017 Forecast	2018 TY	2019 TY
Labour	88,888	(5,633)	83,255	90,566	77,547	81,574	85,269	86,830
SEM	26,825	(41)	26,784	31,927	25,048	25,694	26,228	26,796
Other[73]	30,922	(1,040)	29,882	36,334	24,687	28,021	29,645	29,634
Cost Allocations	(7,066)	(118)	(7,184)	(7,906)	(3,370)	(948)	1,235	2,073
Total	**139,569**	**(6,832)**	**132,737**	**150,921**	**123,912**	**134,341**	**142,377**	**145,333**

Labour

Table 3-19 provides a breakdown of Hydro's Labour costs from the 2015 Test Year, as submitted, to the 2019 Test Year.

Table 3-19 Operation Costs - Labour Costs 2015 TY to 2019 TY ($000s)

Labour Cost	2015 TY	2015 GRA Order	2015 Approved TY	2015 Actual	2016 Actual	2017 Forecast	2018 TY	2019 TY
Labour related	75,611	(5,633)	69,978	73,287	64,481	71,107	73,906	75,224
EFB[74]	8,371	-	8,371	6,690	6,902	6,285	6,489	6,705
Overtime	4,906	-	4,906	10,589	6,164	4,182	4,874	4,901
Total	**88,888**	**(5,633)**	**83,255**	**90,566**	**77,547**	**81,574**	**85,269**	**86,830**

In the 2018 and 2019 Test Years, Labour Costs are forecast to be approximately 60% of Hydro's operating costs. Labour Costs are forecast to increase 4.3%, or $3.6 million, from the 2015 Approved Test Year to the 2019 Test Year. This represents an annual increase of approximately 1.1%, or $0.9 million, per year through the five year period.

Labour related costs of $75.2 million in the 2019 Test year are on par with the 2015 Test Year as submitted. This results from: (i) increased capital labour of $4.0 million; (ii) a transfer of staff from Hydro to Nalcor which resulted in labour cost reductions of $4.0 million; offset by (iii) structural salary increases of $3.8 million; (iv) increases of $2.3 million in costs associated with

[73] Please refer to Schedule 3-IX for additional information.
[74] Employee Future Benefits.

changes in FTEs; and (v) an increase of $1.3 million in fringe benefits and other salary costs. Employee future benefit costs decreased due to changes in actuarial assumptions that impacted the cost base.

System Equipment and Maintenance

System equipment and maintenance costs contain materials and contract labour costs associated with maintenance activity. Year over year variations reflect changes in operational requirements.

Other

Other costs include travel, professional services, insurance, and other costs. For a complete list, please refer to Schedule 3-IX. Costs in this category are forecast to decrease in the 2019 Test Year compared to the 2015 Test Year primarily due to a reduction in transportation and travel related costs.

Cost Allocations

Table 3-20 provides a breakdown of the items contained in the Cost Allocations category.

Table 3-20 Operation Costs - Cost Allocation 2015 TY to 2019 TY ($000s)

Cost Allocation	2015 TY	2015 GRA Order	2015 Approved TY	2015 Actual	2016 Actual	2017 Forecast	2018 TY	2019 TY
Hydro Admin Recovery[75]	(5,652)	(118)	(5,770)	(6,514)	(3,235)	(2,271)	(2,256)	(2,306)
Nalcor Admin Fee[76]	-	-	-	-	3,350	3,948	4,642	6,242
Business System Fee[77]	-	-	-	-	253	1,029	2,542	1,894
Productivity Allowance[78]	-	-	-	-	-	-	(1,039)	(1,102)
CDM Program Deferral[79]	(695)	-	(695)	-	(1,153)	(2,100)	(2,100)	(2,100)
Phase II Cost Deferral[80]	-	-	-	-	(869)	(1,000)	-	-
Other cost recoveries[81]	(719)	-	(719)	(1,392)	(1,716)	(554)	(554)	(555)
Total	**(7,066)**	**(118)**	**(7,184)**	**(7,906)**	**(3,370)**	**(948)**	**1,235**	**2,073**

Operating Costs by Function

Table 3-21 summarizes Hydro's costs by two functional categories: Operations and General and Administration from the 2015 Test Year, as submitted, to the 2019 Test Year.

[75] Hydro recovers costs associated with the operation of Hydro Place from the other lines of business by charging rent to occupants. As well, Hydro recovers costs associated with the telephones and network fees from other lines of business. In 2015, Admin Fee recoveries included recoveries for human resources, safety and health and information systems. These services are no longer provided by Hydro for all lines of business. Please refer to Exhibit 5.

[76] Nalcor charges Hydro for services provided for human resources, health and safety, environmental services, and information systems. In 2015, these services were provided by Hydro to all lines of business and accordingly, there were no charges from Nalcor for these services. Please refer to Exhibit 5.

[77] Fees associated with the Business System Transformation program outlined in Section 3.7.1 of this evidence are also included in this category.

[78] This is an allowance imposed by Hydro Management to reflect the Company's commitment to cost management and efficiency activities.

[79] Deferral of costs associated with Conservation and Demand Management costs. Please refer to Chapter 2: Customers for more information on these programs.

[80] Order No. P.U. 13 (2016) approved the deferral of costs related to Phase II of the investigation into the reliability and adequacy of power on the Island Interconnected system after the interconnection with the Muskrat Falls generating station.

[81] Includes general cost recoveries and varies from year to year.

Table 3-21 Operating Costs by Function 2015 TY to 2019 TY ($000s)

Function	2015 TY	2015 GRA Order	2015 Approved TY	2015 Actual	2016 Actual	2017 Forecast	2018 TY	2019 TY
Operations	107,551	-	107,551	117,025	97,844	99,879	104,476	107,551
General and Administration	32,018	-	32,018	36,638	26,068	34,462	37,901	37,782
Adjustment - EFB[82]	-	-	-	(2,742)	-	-	-	-
GRA Order Disallowances	-	(6,832)	(6,832)	-	-	-	-	-
Total	**139,569**	**(6,832)**	**132,737**	**150,921**	**123,912**	**134,341**	**142,377**	**145,333**

Operations

Table 3-22 provides costs associated with the Operations category broken down by function from the 2015 Test Year, as submitted, to the 2019 Test Year.

Table 3-22 Operating Costs - Operations 2015 TY to 2019 TY ($000s)

Operations	2015 TY	2015 Actual	2016 Actual	2017 Forecast	2018 TY	2019 TY
Transmission & Distribution & NLSO	54,920	59,718	47,495	46,168	46,999	47,605
Production	41,143	46,372	41,526	41,500	43,253	43,742
Engineering Services	4,176	3,772	2,424	4,069	4,591	4,964
Information & Operations Technology	7,312	7,163	6,399	8,142	9,633	11,240
Total	**107,551**	**117,025**	**97,844**	**99,879**	**104,476**	**107,551**

Total costs in the Operations category in the 2019 Test Year are forecast to be at the level consistent with the 2015 Test Year, as submitted.[83] Reduced costs in Transmission and Rural Operations primarily relate to: (i) increases in capital work; (ii) reductions in labour-related costs; and (iii) cost reductions associated with the transfer of the warehouse function to the Financial Services division. Cost increases in Production are primarily driven by the requirements associated with the operation of gas turbines.[84] Information and Operations Technology includes costs that support information systems management and infrastructure. This includes the technical operation of the Energy Control Centre (ECC) as well as general

[82] The EFB adjustment was not allocated by Division.
[83] Hydro did not allocate the disallowance noted in Order No. P.U. 49(2016) by Functional department.
[84] Note that these costs exclude fuel costs.

operational business support, which is provided by Nalcor through an Administration Fee.[85] Cost increases in this category are driven by: (i) operating costs associated with the ECC; and (ii) additional information technology support costs.

In both the 2018 and 2019 Test Years, Hydro has included an allowance to reflect the impact of cost management and efficiency activities. This results in a reduction of $0.8 million in total costs forecast for each of the 2018 and 2019 Test Years.

General and Administration

Table 3-23 provides the Hydro's costs associated with the General and Administration category broken down by function from the 2015 Test Year, as submitted, to the 2019 Test Year.

Table 3-23 Operating Costs - General and Administration 2015 TY to 2019 TY ($000s)

General and Administration	2015 TY	2015 Actual	2016 Actual	2017 Forecast	2018 TY	2019 TY
Executive Leadership	1,868	2,537	1,909	2,771	2,793	2,859
Financial Services	8,584	9,819	6,084	10,118	10,970	11,199
Business System Fee	-	-	253	1,029	2,542	1,894
Corporate Services & Regulatory Affairs	21,566	24,282	17,822	20,544	21,596	21,830
Total	**32,018**	**36,638**	**26,068**	**34,462**	**37,901**	**37,782**

Costs in the General and Administration category are forecast to increase $5.8 million in the 2019 Test Year compared to the 2015 Test Year.

Cost increases in Executive Leadership relate to the creation of a dedicated and separate executive team for Hydro.[86] Financial Services costs reflect a transfer of the warehouse function from Operations to Financial Services and overall increase in costs. Corporate Services and Regulatory Affairs costs for the 2018 and 2019 Test Years are on par with the 2015 Test Year levels.

[85] For additional information on the Administration Fee, please refer to Exhibit 5.
[86] Refer to Section 3.2.

In both the 2018 and 2019 Test Years, an allowance to reflect the impact of cost management and efficiency activities is included. This results in a reduction $0.3 million total costs forecast for the 2018 and 2019 Test Years.

Business Systems Transformation Program

As part of shared services, Hydro is a client of the corporate Business Systems Transformation program that is being led by its parent company, Nalcor. The Business Systems Transformation program has an executive level steering committee and project management structure with senior representatives and business expertise from Hydro.

The Business Systems Transformation program was established to address technical and functional concerns with current processes and systems not meeting evolving needs. The current Enterprise Resource Planning (ERP) system, JD Edwards World, which Hydro installed in 1999, has limited functionality and workflow capabilities, and has an outdated user interface. There are many manual processes performed outside of systems, leaving staff to rely on paper, Microsoft Excel, and other software tools. Data standardization, reporting, and integrating budgeting and forecasting tools is challenging, inefficient and, like many manual processes, can be prone to error. The standardization of Information Management (IM) practices has been identified as a gap across the organization, and is required for legislative compliance.

Hydro is, and has been, involved in all phases of the program including: developing the approach, requirements and analysis, research, the Request for Proposal process, design, build, and testing to ensure requirements are met. The program has three main projects: upgrading JD Edwards from World to EnterpriseOne; implementing the Planning, Budgeting and Forecasting solution Cognos TM1; and implementing the corporate IM program.

Hydro will benefit from enhanced functionality and processes in all areas of its business, including improved data analysis and reporting capabilities, reduction in manual processes and interfaces, electronic workflows, integration of budgets and forecasts, and a modern and efficient user interface. In addition, Hydro will able to: expand its IM toolsets, policies, and guidelines; manage and secure its information assets; and increase its compliance with legislative and regulatory requirements.

3.7.3 Capital Costs

Hydro's annual capital budget reflects a large number of assets that are required to support the electrical system and ensure Hydro is able to meet demand and provide reliable service to its customers. In 2015 and 2016, Hydro invested approximately $125 million and $204 million, respectively, focused on revitalizing and replacing aging infrastructure, and increasing system capacity due to load growth on the Avalon Peninsula.

In 2017, Hydro is forecasting to spend approximately $370 million, including over $167 million on transmission infrastructure, including two previously approved major projects to increase transmission capacity on the Avalon; the multi-year upgrade of the transmission corridor between Soldiers Pond to Hardwoods (TL266), and the transmission line from Bay d'Espoir to Western Avalon (TL267).[87] As well, in 2017, Hydro plans on investing approximately 10.8 million at its terminal stations as part of the second year of a five-year, accelerated breaker replacement program across the province.

In 2018, Hydro is proposing to spend approximately $206 million in capital projects. This includes $10.3 million for the first year of a new project called the Hydraulic Generation Refurbishment and Modernization that consolidates all planned hydraulic generation-sustaining capital work into a single project. This year's proposals also include other stand-alone projects to improve reliability, efficiency, and safety of the hydraulic assets, including proposals to ensure the integrity of Penstock 1 at Bay d'Espoir, installation of remote operation of the Salmon River Spillway (near Bay d'Espoir), and implementation of energy efficiency improvements for heating and lighting at multiple hydraulic plants.

[87] From 2015 to 2018, an estimated total of $292 million will be expended on TL267. This project was approved by the Board in Order No. P.U. 53(2014).

Hydro continues its upgrade of power transformers and circuit breakers within its terminal stations. Approximately $24 million of the transmission expenditures planned for 2018 reflect the newly proposed transmission asset to the Happy Valley Terminal Station that will increase transfer capacity to meet the load requirements of Labrador East.

These capital expenditures reflect the required investment in plant and equipment to meet customer demands. Hydro expects the level of investment to continue as it refurbishes and replaces equipment to ensure long-term reliability of electrical energy supply and functionality of its equipment. Over the period 2015 to 2019 Test Year, Hydro will have invested on average, $210 million a year in its electrical system.

3.8 Island Interconnection with the North American Grid

The development of the Muskrat Falls Project associated transmission facilities will have implications for Newfoundland and Labrador's electricity system including the benefit of increased reliability and strategic export capabilities.[88] It is anticipated that both the Labrador-Island Link and the Maritime Link interconnections will be in operation in 2018. Interconnection with the North American grid and the move away from reliance on Holyrood is the biggest change that Hydro has experienced since the 1960's. Hydro acknowledges this change and is taking appropriate measures to ensure it is prepared, and that it can take advantage of the new opportunities it will be presented.[89]

3.8.1 Integration Management and Preparation

With the changes facing Hydro in the near term, it has become clear that there is a need to coordinate the activities the Company must undertake to ensure its ability to capitalize on the opportunities provided by the interconnection of these new HVdc transmission lines. Hydro has therefore created a new temporary position, Manager, Interconnection & Integration, reporting

[88] Incudes Muskrat Falls Generation Plant, the Labrador Transmission Assets, the Labrador-Island Link, and the Maritime Link.
[89] The interconnection of Muskrat Falls is currently under review by the Board in its *Investigation and Hearing into Supply Issues and Power Outages on the Island Interconnected System - Phase Two.*

directly to the President. The role of this position is to ensure alignment on, and awareness of, key aspects of the integration, the new assets, and the associated interconnection of the island. It includes overall responsibility for ensuring all activities necessary for the successful integration and operation of these assets are documented, assigned to respective owners, and that progress and schedule are tracked and reported to ensure critical dates are met. This position is also accountable for integration-related risk management for Hydro.

3.8.2 System Reliability Impact

With the development of the Muskrat Falls generation plant, and connection to the North American grid, the reliability of supply to customers will be improved, driven by the following:

- the Maritime Link will provide an alternate supply of up to 300 MW to the Island system further enhancing reliability.
- in the post Muskrat Falls system, the requirement to utilize under frequency load shedding to mitigate on Island generation loss will be reduced, thus reducing customer outages and further improving reliability. For loss of an on Island generator, sufficient spinning reserves will be scheduled between on Island generators and the Labrador Island Link to ensure acceptable frequency response of the system with less under frequency load shedding on the Island.

3.8.3 Reliability Standards

Hydro is currently evaluating its level of compliance with the North American Electric Reliability Corporation (NERC)[90] reliability standards and the Northeast Power Coordinating Council (NPCC)[91] regional reliability criteria, in its consideration of the appropriate reliability framework

[90] NERC is a not-for-profit international regulatory authority whose mission is to assure the reliability and security of the bulk power systems in North America. NERC Reliability Standards define the reliability requirements for planning and operating the North American bulk power system and are developed using a results-based approach that focuses on performance, risk management, and entity capabilities.

[91] Each NERC region has regional reliability standards, that once approved become part of NERC's reliability standards. There are eight associated regional entities that perform delegated reliability functions on behalf of NERC. The NPCC is one of these entities and is responsible for promoting and enhancing the reliability of the interconnected bulk power system in Northeastern North America. Its geographical region includes the State of New York and the six New England states as well as the Canadian provinces of Ontario, Québec, and the Maritime provinces of New Brunswick and Nova Scotia.

for the Newfoundland and Labrador electricity system. While Hydro has not been mandated by the Provincial Government to implement NERC standards, the Company recognizes the benefits that the NERC reliability standards provide and, as a prudent operational measure, is in the preliminary stages of reviewing and assessing the standards that are applicable for adoption into the Island Interconnected System. Hydro is also reviewing the approach it will use to implement applicable NERC reliability standards and the impacts that these standards will have on the Island Interconnected System when the Island of Newfoundland interconnects with Nova Scotia and Labrador via the Maritime and Labrador-Island links, respectively.

In addition to reviewing and assessing the NERC standards, Hydro is also analyzing other industry recognized standards, including those developed by the Federal Energy Regulatory Commission (FERC). Consistent with industry practice, functional separation should exist between power production and the Newfoundland and Labrador System Operator (NLSO) transmission operations. FERC imposes additional requirements in its Standards of Conduct regulations that govern that employees of the NLSO function independently from Nalcor Energy Marketing employees. The purpose of this requirement is to ensure that there is no collaboration or exchange of non-public transmission information between affiliated business units which could impair non-discriminatory, open system access within the wider electricity market.

In accordance with FERC standards, the Newfoundland and Labrador System Operator (NLSO) has been created to act as the independent system operator for the Province.[92] Although the NLSO will reside within Hydro, it will operate the facilities owned by Hydro, Nalcor Power Supply, and interconnections with Emera's Maritime Link assets on the Island. The NLSO will represent all interests on the transmission and distribution network and will be governed by a set of rules and regulations that ensures fair and equitable treatment of all entities seeking access to the network.

[92] Please refer to Exhibit 2 for more information.

3.9 Conclusion

Hydro has undergone organizational and cultural changes to ensure it meets its mandate to provide safe, reliable, cost-effective electricity service to its customers. With the establishment of Hydro as a standalone entity, Hydro is better able to focus on driving outcomes that are best suited for the Company, independent of its parent company, Nalcor.

To better manage customer expectations, Hydro has moved towards a model of more frequent and informative customer communications, a holistic focus on the provincial customer base, and improved event protocols. These tools create accountability within the Company and ensure appropriate measures are taken to provide least cost reliable service. The Company has also realigned its processes to promote prudent capital and operational spending with emphasis on improved reliability and maintaining the safety of its employees and the general public.

In order to continue to provide reliable service to its customers, Hydro has revised its planning model to better represent the changing electrical system, and is managing its involvement in activities related to North American grid interconnection.

The Company's renewed customer-centric cost reduction and reliability initiatives enable a clear focus on Hydro specific needs and ensure that Hydro has control over decisions that influence how it operates, and accountability for all system aspects, for the benefit of customers.

Chapter 3 - Schedule I

Actual and Forecast Electricity Requirements for 2015 to 2019 – Island Interconnected System

Newfoundland and Labrador Hydro
Actual and Forecast Electricity Requirements for 2015 to 2019
Island Interconnected System

	2015 Test Year		2015 Actual		2016 Forecast[1]		2016 Actual		2017 Forecast[2]		2018 Test Year[2]		2019 Test Year[2]	
	MW	GWh	MW	GWh	MW	GWh	MW	GWh	MW	GWh	MW	GWh	MW	GWh
Newfoundland Power[3]	1,295.0	5,924.1	1,307.3	6,072.1	1,333.4	5,881.1	1,341.1	5,844.7	1,325.1	5,824.7	1,322.8	5,824.5	1,322.3	5,833.6
NLH Rural Interconnected	95.2	463.9	99.0	476.6	97.4	463.1	96.4	476.5	100.0	464.7	98.6	457.0	96.9	451.5
Industrial Customers[4]	81.5	621.4	82.8	498.5	77.1	537.1	79.0	510.8	92.2	643.4	97.5	726.0	96.5	743.3
Total Deliveries[5]	1,448.3	7,009.4	1,474.0	7,047.3	1,477.8	6,881.3	1,445.1	6,832.0	1,475.8	6,932.8	1,490.5	7,007.5	1,487.6	7,028.4
Transmission Losses[5,6]	74.7	225.7	76.0	238.5	70.6	228.5	75.9	207.2	78.3	245.0	79.5	215.0	79.0	206.9
Hydro Island Interconnected System Electricity Requirement[7,8]	1,523.0	7,235.1	1,550.0	7,285.8	1,548.4	7,109.8	1,521.0	7,039.2	1,554.1	7,177.8	1,570.0	7,222.5	1,566.6	7,235.3

Notes:
1. The 2016 Forecast is sourced to the March 16, 2016 Island Operating Load Forecast.
2. The 2017 to 2019 Forecast is sourced to the March 2017 Island Operating Load Forecast.
3. Newfoundland Power MW's reflect the maximum annual MW purchased by Newfoundland Power from Hydro.
4. Industrial MW's for 2015 and 2016 actuals reflect sum of annual maximum customer demands.
5. MW's for Total Deliveries and Transmission Losses are coincident with system peak. MW transmission losses include Hydro's station services.
6. MW Transmission losses include the station service requirements for Holyrood, Bottom Brook, and Soldiers Pond as appropriate.
7. Hydro's Requirement MW's are Hydro system coincident MW's and include customer firm demand requirements only. Forecast MW's are annual maximums.
8. Differences in totals vs. addition of individual components due to rounding.

Chapter 3 – Schedule II

Actual and Forecast Electricity Requirements for 2015 to 2019 – Labrador Interconnected System

Newfoundland and Labrador Hydro
Actual and Forecast Electricity Requirements for 2015 to 2019
Labrador Interconnected System

	2015 Test Year		2015 Actual		2016 Forecast		2016 Actual		2017 Forecast		2018 Test Year		2019 Test Year	
	MW	GWh	MW	GWh	MW	GWh	MW	GWh	MW	GWh	MW	GWh	MW	GWh
Hydro Rural Interconnected	160.0	688.1	153.0	634.6	156.2	637.7	150.2	626.0	160.7	682.3	162.4	688.6	161.5	688.5
Department of National Defence	-	10.2	-	0.0	-	-	-	0.1	-	0.0	-	0.0	-	0.0
Iron Ore Company of Canada	252.0	1,719.9	243.1	1,703.5	252.5	1,785.1	252.5	1,753.0	245.0	1,733.1	245.0	1,733.1	245.0	1,733.1
Wabush Mines	18.0	70.1	1.9	5.4	0.7	2.8	0.7	3.6	0.4	2.4	0.3	1.2	-	-
Industrial Customers	270.0	1,790.0	244.9	1,708.8	253.2	1,787.9	253.2	1,756.6	245.4	1,735.5	245.3	1,734.3	245.0	1,733.1
Total Deliveries	383.5	2,488.3	379.1	2,343.4	362.8	2,425.6	370.1	2,382.7	368.0	2,417.8	369.4	2,422.9	368.3	2,421.6
Transmission Losses	48.3	188.6	31.2	149.5	45.7	154.0	46.9	148.4	31.0	150.9	31.3	151.1	30.7	150.9
Total Hydro Labrador Interconnected Electricity Requirement	431.8	2,676.9	410.3	2,492.9	408.5	2,579.6	417.0	2,531.1	399.0	2,568.7	400.7	2,574.0	399.0	2,572.5

Notes:
1. Actuals reflect rounded values to the nearest tenth of a GWh.
2. Actual customer peaks are annual maximums. System peak excludes interruptible and secondary load.
3. The 2016 Forecast is sourced to the March 16, 2016 Island Operating Load Forecast.
4. The 2017 to 2019 Forecast is sourced to the March 2017 Island Operating Load Forecast.
5. Sales to CFB Goose Bay are secondary sales.
6. Demands for Total Deliveries and Transmission Losses are coincident with system peak.

Chapter 3 - Schedule III

Actual and Forecast Electricity Requirements for 2015 to 2019 – Isolated Systems

Newfoundland and Labrador Hydro
Actual and Forecast Electricity Requirements for 2015 to 2019
Isolated System

	2015 Test Year		**2015 Actual**		**2016 Actual**		**2017 Forecast**		**2018 Test Year**		**2019 Test Year**	
	KW[2]	**MWh[3]**	**KW[2]**	**MWh[3]**	**KW[2]**	**MWh[3]**	**KW[2]**	**MWh[3]**	**KW[2]**	**MWh[3]**	**KW[2]**	**MWh[3]**
L'Anse au Loup	5,736	24,953	5,598	25,796	5,959	26,734	6,015	26,681	6,060	26,789	6,105	26,988
Labrador Isolated Systems	10,448	44,911	10,469	43,481	10,463	43,875	10,750	45,717	10,851	46,140	10,901	46,342
Total Labrador Isolated Combined Systems	16,184	69,864	16,067	69,278	16,422	70,609	16,766	72,398	16,912	72,929	17,006	73,330
Island Isolated Systems	2,263	7,645	2,351	7,624	2,233	7,284	2,108	7,581	2,098	7,545	2,090	7,516
Total Isolated Systems[4]		77,509		76,901		77,893		79,979		80,474		80,846

Notes:

1. Forecast source is Hydro Spring 2016 Rural Operating Load Forecast.
2. Peaks are non-coincident net annual maximums.
3. Net production excludes station services.
4. Differences in totals vs. addition of individual components due to rounding.

Chapter 3 - Schedule IV
Production Plan for 2017 to 2019

Newfoundland and Labrador Hydro
Production Plan for 2017-2019
Island Interconnected System

Production Plan (Net Generation GWh)
Year: 2017

									Thermal	Gas Turbine			Diesel		Purchases									
Month	LOAD	BDE	HLK	USL	CAT	GCL	MINI	PRV	Holyrood	HWD	SVL	HRD	HRD	GNP	Deer Lake Power Secondar	Nalcor GF and BF	Nalcor Star Lake	Rattle Brook	Corner Brook CoGen	Nalcor Buchans	St. Lawrence Wind	Fermeuse Wind	Total Power Purchases	Total Supplied
January	848.1	298.0	53.2	62.2	32.7	24.2	0.3	3.3	267.8	3.0	0.1	9.8	0.2	0.1	0.0	54.8	11.2	0.7	6.3	0.0	11.2	9.0	93.3	848.1
February	770.4	301.8	46.2	58.1	35.8	22.7	0.3	2.9	207.4	2.9	0.1	6.4	0.2	0.1	0.0	49.4	10.6	0.5	5.0	0.0	11.2	9.0	85.6	770.4
March	777.2	281.4	41.6	62.0	51.1	23.8	0.3	3.7	213.8	1.8	0.1	5.3	0.2	0.1	0.0	54.2	12.2	0.6	5.8	0.0	10.6	8.5	92.0	777.2
April	624.8	269.0	26.6	60.3	36.5	25.8	0.4	4.7	118.3	1.6	0.1	3.2	0.1	0.0	0.0	41.9	12.1	1.6	5.6	0.0	9.4	7.6	78.2	624.8
May	526.3	200.9	27.8	46.9	51.1	23.8	0.6	3.9	84.0	0.1	0.1	0.1	0.0	0.0	0.0	52.5	12.1	2.6	5.7	0.0	7.9	6.3	87.2	526.3
June	446.0	174.7	26.6	51.9	49.0	17.3	0.5	2.0	42.1	0.1	0.1	0.1	0.0	0.0	0.0	52.7	10.3	1.6	6.1	0.0	6.1	4.9	81.7	446.0
July	408.1	157.9	23.1	48.0	31.8	15.0	0.4	1.4	43.7	0.1	0.1	1.5	0.0	0.0	0.0	55.5	12.9	0.8	5.6	0.0	5.8	4.6	85.2	408.1
August	404.9	181.8	18.5	54.8	35.0	17.5	0.3	1.5	7.8	0.1	0.1	13.2	0.0	0.0	0.0	45.6	12.9	0.8	4.2	0.0	6.0	4.8	74.4	404.9
September	409.3	166.5	20.8	38.9	41.8	13.7	0.3	1.8	54.6	0.1	0.1	0.1	0.0	0.0	0.0	38.5	10.7	1.2	6.2	0.0	7.8	6.2	70.6	409.3
October	519.9	197.1	33.6	46.0	35.8	20.2	0.4	3.1	104.2	0.1	0.1	0.1	0.0	0.0	0.0	44.2	12.9	1.6	5.4	0.0	8.5	6.8	79.4	519.9
November	637.8	254.0	39.3	58.1	38.0	27.1	0.4	3.9	137.3	0.9	0.1	0.6	0.0	0.0	0.0	43.3	11.1	1.8	4.3	0.0	9.7	7.8	78.0	637.8
December	805.0	298.7	41.6	62.3	34.2	27.1	0.3	3.9	240.5	0.9	0.1	3.0	0.1	0.1	0.0	54.2	11.3	1.1	6.3	0.0	10.8	8.7	92.3	805.0
TOTAL	7177.8	2781.6	399.0	649.3	473.0	258.2	4.5	36.0	1521.5	11.4	0.8	43.5	0.8	0.5	0.0	587.0	140.3	14.8	66.5	0.0	104.8	84.4	997.9	7177.8

Newfoundland and Labrador Hydro
Production Plan for 2017-2019
Island Interconnected System

Production Plan (Net Generation GWh)
Year: 2018

									Thermal	Gas Turbine			Diesel		Purchases									
Month	LOAD	BDE	HLK	USL	CAT	GCL	MINI	PDR	Holyrood	HWD	SVL	HRD	HRD	GNP	Deer Lake Power Secondar	Nalcor GF and BF	Nalcor Star Lake	Rattle Brook	Corner Brook CoGen	Nalcor Buchans	St. Lawrence Wind	Fermeuse Wind	Total Power Purchases	Total Supplied
January	855.2	282.4	47.2	59.2	52.3	23.1	0.3	3.2	280.8	3.0	0.1	9.7	0.2	0.1	0.0	54.0	12.5	0.7	6.3	0.0	11.2	9.0	93.7	855.2
February	775.7	251.9	41.0	52.9	57.2	21.6	0.3	2.8	252.7	2.9	0.1	6.4	0.2	0.1	0.0	48.8	11.3	0.5	5.0	0.0	11.2	9.0	85.8	775.7
March	783.2	213.5	36.9	44.8	81.6	22.7	0.3	3.6	280.8	1.8	0.1	5.2	0.2	0.1	0.0	53.7	12.5	0.6	5.8	0.0	10.6	8.5	91.7	783.2
April	625.2	223.2	23.6	46.8	58.3	24.6	0.4	4.5	146.2	1.6	0.0	3.1	0.1	0.0	0.0	56.2	12.3	1.6	5.6	0.0	9.4	7.6	92.7	625.2
May	531.9	193.4	24.6	40.6	81.6	22.7	0.6	3.8	70.6	0.0	0.0	0.1	0.0	0.0	0.0	58.8	12.6	2.6	5.7	0.0	7.9	6.3	94.0	531.9
June	449.4	203.4	23.6	42.7	78.2	16.5	0.5	1.9	4.1	0.0	0.0	0.1	0.0	0.0	0.0	47.8	11.9	1.6	6.1	0.0	6.1	4.9	78.4	449.4
July	411.8	200.0	20.5	42.0	50.8	14.3	0.4	1.3	0.0	0.0	0.0	0.1	0.0	0.0	0.0	52.6	13.0	0.8	5.6	0.0	5.8	4.6	82.3	411.8
August	405.3	191.1	16.4	40.1	55.9	16.7	0.3	1.5	0.0	0.0	0.0	0.1	0.0	0.0	0.0	54.4	13.0	0.8	4.2	0.0	6.0	4.8	83.2	405.3
September	414.5	195.3	18.5	41.0	66.7	13.1	0.3	1.8	0.0	0.0	0.0	0.1	0.0	0.0	0.0	49.9	6.5	1.2	6.2	0.0	7.8	6.2	77.8	414.5
October	523.7	220.8	29.8	46.3	57.2	19.3	0.4	3.0	72.0	0.0	0.0	0.1	0.0	0.0	0.0	39.7	12.9	1.6	5.4	0.0	8.5	6.8	74.9	523.7
November	640.0	219.1	34.9	46.0	60.6	25.8	0.4	3.8	167.0	0.9	0.0	0.6	0.0	0.0	0.0	45.9	11.2	1.8	4.3	0.0	9.7	7.8	80.7	640.0
December	806.6	255.9	36.9	53.7	54.6	25.8	0.3	3.8	280.2	0.9	0.0	2.9	0.1	0.1	0.0	53.3	11.3	1.1	6.3	0.0	10.8	8.7	91.4	806.6
TOTAL	7222.5	2650.0	354.0	556.0	755.0	246.0	4.5	35.0	1554.4	11.1	0.5	28.2	0.8	0.5	0.0	615.1	140.9	14.8	66.5	0.0	104.8	84.4	1026.5	7222.5

Newfoundland and Labrador Hydro
Production Plan for 2017-2019
Island Interconnected System

Production Plan (Net Generation GWh)
Year: 2019

									Thermal	Gas Turbine			Diesel		Purchases									
Month	LOAD	BDE	HLK	USL	CAT	GCL	MINI	PDR	Holyrood	HWD	SVL	HRD	HRD	GNP	Deer Lake Power Secondar	Nalcor GF and BF	Nalcor Star Lake	Rattle Brook	Corner Brook CoGen	Nalcor Buchans	St. Lawerence Wind	Fermeuse Wind	Total Power Purchases	Total Supplied
January	865.0	290.2	47.2	61.2	52.4	23.1	0.3	3.2	280.8	3.0	0.1	9.7	0.2	0.1	0.0	54.0	12.5	0.7	6.3	0.0	11.2	9.0	93.6	865.0
February	779.0	254.4	41.0	53.6	57.3	21.6	0.3	2.8	252.7	2.9	0.1	6.4	0.2	0.1	0.0	48.7	11.3	0.5	5.0	0.0	11.2	9.0	85.6	779.0
March	787.8	234.9	36.9	49.5	81.9	22.7	0.3	3.6	259.0	1.8	0.1	5.2	0.2	0.1	0.0	53.7	12.5	0.6	5.8	0.0	10.6	8.5	91.7	787.8
April	632.8	235.3	23.6	49.6	58.5	24.6	0.4	4.5	139.2	1.6	0.0	3.1	0.1	0.0	0.0	55.7	12.4	1.6	5.6	0.0	9.4	7.6	92.2	632.8
May	533.6	196.0	24.6	41.3	81.9	22.7	0.6	3.8	68.4	0.0	0.0	0.1	0.0	0.0	0.0	59.0	12.8	2.6	5.7	0.0	7.9	6.3	94.3	533.6
June	451.9	193.7	23.6	40.9	78.4	16.5	0.5	1.9	17.3	0.0	0.0	0.1	0.0	0.0	0.0	48.3	12.0	1.6	6.1	0.0	6.1	4.9	79.0	451.9
July	422.0	208.0	20.5	43.9	51.0	14.3	0.4	1.3	0.0	0.0	0.0	0.1	0.0	0.0	0.0	52.8	13.0	0.8	5.6	0.0	5.8	4.6	82.5	422.0
August	404.1	189.5	16.4	39.9	56.0	16.7	0.3	1.5	0.0	0.0	0.0	0.1	0.0	0.0	0.0	54.8	13.0	0.8	4.2	0.0	6.0	4.8	83.6	404.1
September	411.8	181.5	18.5	38.3	66.9	13.1	0.3	1.8	13.4	0.0	0.0	0.1	0.0	0.0	0.0	50.0	6.5	1.2	6.2	0.0	7.8	6.2	77.9	411.8
October	522.7	216.8	29.8	45.7	57.3	19.3	0.4	3.0	75.6	0.0	0.0	0.1	0.0	0.0	0.0	39.5	12.9	1.6	5.4	0.0	8.5	6.8	74.7	522.7
November	632.4	206.9	34.9	43.6	60.8	25.8	0.4	3.8	174.0	0.9	0.0	0.6	0.0	0.0	0.0	45.4	11.5	1.8	4.3	0.0	9.7	7.8	80.6	632.4
December	792.2	243.8	36.9	51.4	54.7	25.8	0.3	3.8	279.9	0.9	0.0	2.9	0.1	0.1	0.0	53.0	11.7	1.1	6.3	0.0	10.8	8.7	91.5	792.2
TOTAL	7235.3	2651.0	354.0	559.0	757.0	246.0	4.5	35.0	1560.3	11.1	0.5	28.2	0.8	0.5	0.0	614.8	142.0	14.8	66.5	0.0	104.8	84.4	1027.4	7235.3

Chapter 3 - Schedule V

Energy Supply and Fuel Expense for 2015 to 2019

Newfoundland and Labrador Hydro
Energy Supply and Fuel Expense for 2015 to 2019
Island Interconnected System

	2015 Test Year[1]	2015 Actual	2016 Actual	2017 Forecast	2018 Test Year	2019 Test Year
Total Energy Requirement (GWh)	7,235.1	7,285.8	7,039.3	7,177.8	7,222.5	7,235.3
Hydraulic Production (GWh)	4,603.6	4,823.4	4,380.4	4,601.5	4,600.5	4,606.4
Energy Receipts and Purchases (GWh)[2]	1,031.0	962.5	917.1	997.9	1,026.5	1,027.4
Gas Turbine/Diesels Production (GWh)[3]	11.4	41.4	120.9	57.0	41.1	41.1
Holyrood Production (GWh)	1,593.0	1,458.5	1,620.9	1,521.5	1,554.4	1,560.3
Holyrood No. 6 Fuel Conversion Factor (kWh/bbl)	618	602	608	603	616	616
Holyrood No. 6 Fuel Consumption (bbl)	2,577,657	2,423,337	2,664,019	2,522,893	2,522,118	2,533,629
No. 6 Fuel Production Cost ($000)	166,026	162,872	123,601	186,476	217,927	220,709
Gas Turbine/Diesel Production Cost ($000)	3,561	14,995	29,210	13,094	12,302	13,024

Notes:
1. 2015 Test Year forecast values reflect Hydro's Compliance filing to Order No. P.U. 49(2016).
2. Energy receipts and purchases in 2015 and 2016 reflect lower than anticipated production at Nalcor Energy Exploits facilities.
3. Standby generation operation in 2015 and 2016 include operation to support system operations and maintenance requirements.

Chapter 3 - Schedule VI

Energy Purchases by Suppliers for 2015 to 2019

Newfoundland and Labrador Hydro
Energy Purchases by Suppliers for 2015 to 2019
Island Interconnected System

Supplier	**2015 Test Year**		**2015 Actuals**		**2016 Actuals**		**2017 Forecast**		**2018 Test Year**		**2019 Test Year**	
	GWh	**$000**	**GWh**	**$000**	**GWh**	**$000**	**GWh**	**$000**	**GWh**	**$000**	**GWh**	**$000**
NP at Hydro Request	-	-	0.6	183	1.7	370	-	-	-	-	-	-
CBPP Secondary[1]	-	-	9.1	174	8.4	231	-	-	-	-	-	-
Star Lake	142.2	5,687	135.3	5,413	135.7	5,429	140.3	5,610	140.9	5,635	142.0	5,679
Rattle Brook	15.0	1,254	13.5	1,103	15.2	1,283	14.8	1,252	14.8	1,264	14.8	1,282
Corner Brook Cogen	51.1	10,281	62.5	11,879	70.6	13,317	66.5	12,934	66.5	12,536	66.5	12,554
St. Lawrence Wind	104.8	7,514	94.8	6,806	103.1	7,420	104.8	7,535	104.8	7,567	104.8	7,598
St. Lawrence Wind Ecoenergy Incentive Credit[2]	-	(638)	-	(466)	-	(828)	-	(560)	-	(621)	-	(31)
Fermeuse Wind	84.4	6,488	87.2	6,744	87.0	6,728	84.4	6,513	84.4	6,539	84.4	6,565
Fermeuse Wind Ecoenergy Incentive Credit[2]	-	(632)	-	(653)	-	(651)	-	(527)	-	(621)	-	(86)
Nalcor Exploits	633.5	25,340	559.5	22,380	495.4	19,815	587.0	23,482	615.1	24,603	614.8	24,594
CBPP Capacity Assistance	-	1,680	0.3	1,752	0.8	2,232	-	2,100	-	2,520	-	2,520
Vale Capacity Assistance	-	442	0.2	304	0.4	371	-	213	-	302	-	302
Vale Capacity Assistance (Curtailable Load)	-	-	-	-	-	-	-	126	-	168	-	168
Praxair Capacity Assistance[3]	-	-	-	-	0.0	35	-	140	-	140	-	140
Total Power Purchases[4]	1,031.0	57,416	962.9	55,618	918.2	55,752	997.9	58,819	1,026.5	60,032	1,027.4	61,286

Notes:

1. CBPP Secondary amounts represent the actuals delivered to the Island Interconnected System.
2. Ecoenergy Incentive Credits are paid to Hydro quarterly at $0.0075/kwh on the eligible production (up to a maximum of 82.78 GWh annually)
3. 2016 Actuals appear as 0 due to rounding.
4. Differences in totals vs. addition of individual components due to rounding.

Chapter 3 – Schedule VII

Monthly No. 6 Fuel Purchase Prices for 2015 to 2019

Newfoundland and Labrador Hydro
Monthly No. 6 Fuel Purchase Prices for 2015 to 2019 ($/bbl)

Month	2015 Test Year	2015 Actual[1]	2016 Actual[1]	2017 Forecast	2018 Test Year	2019 Test Year
January	57.55	57.38	35.00	73.18	88.39	87.80
February	59.85	70.27	36.76	73.18	90.49	87.80
March	61.41	65.67	38.12	73.18	85.59	87.80
April	61.41	60.55	41.66	72.90	83.70	87.80
May	62.64	-	50.59	74.30	84.09	87.80
June	62.64	-	-	75.78	85.60	87.80
July	62.64	74.61	-	77.60	87.50	87.80
August	62.64	-	55.85	78.70	88.80	87.80
September	62.64	-	58.30	79.38	87.40	87.80
October	66.51	-	64.18	84.90	87.79	87.80
November	71.70	51.81	59.07	88.08	88.29	87.80
December	76.05	55.31	69.53	88.58	83.69	87.80
Weighted Purchase Price	**64.41**	**60.55**	**47.55**	**78.84**	**86.68**	**87.80**

Notes:
1. There were no purchases in months with a blank.
2. 2015 Test Year forecast values reflect Hydro’s Compliance filing to Order No. P.U. 49(2016).

Chapter 3- Schedule VIII

Isolated Fuel and Purchased Power Costs for 2015 to 2019

Newfoundland and Labrador Hydro
Isolated Fuel and Purchased Power Costs for 2015 to 2019 ($000)

	2015 Test Year [1]	2015 Actual	2016 Actual	2017 Forecast[2]	2018 Test Year[2]	2019 Test Year[2]
Diesel Fuel						
Total Diesel Fuel[3]	18,592	16,227	13,994	17,769	19,561	20,976
Purchased Power						
L'Anse au Loup[4]	3,055	2,679	2,367	3,090	3,397	3,717
Ramea[5]	232	166	138	182	213	227
Mary's Harbour	-					
Total Purchased Power	3,287	2,844	2,505	3,272	3,610	3,944
Total[6]	**21,879**	**19,071**	**16,499**	**21,041**	**23,171**	**24,920**

Notes:
1. 2015 Test Year Forecast sourced to October 2014 Isolated Fuel and Power Purchase budgets.
2. Forecast dollars based on Hydro's Rural Load Forecast, Spring 2016 and a fuel price forecast, prepared February 2017
3. L'Anse au Loup fuel purchases include deferred fuel savings.
4. Ramea power purchases includes Frontier and Nalcor WHD and are based on historical averages. It is assumed that wind generation will be available throughout the forecast period.
5. Power purchases from Hydro Quebec are assumed to be available throughout the forecast period.
6. Differences in totals vs. addition of individual components due to rounding.

Chapter 3 - Schedule IX

Total Operating Expenses by Cost Type

Newfoundland and Labrador Hydro
Total Operating Expenses by Cost Type
$ thousands

	2015 TY	2015 GRA Order	2015 Approved TY	2015 Actual	2016 Actual	2017 Forecast	2018 Test Year	2019 Test Year
Labour								
Labour related costs	75,611	(5,633)	69,978	73,287	64,481	71,107	73,906	75,224
Employee future benefits	8,371	-	8,371	6,690	6,902	6,285	6,489	6,705
Overtime	4,906	-	4,906	10,589	6,164	4,182	4,874	4,901
Total Labour	88,888	(5,633)	83,255	90,566	77,547	81,574	85,269	86,830
System Equipment and Maintenance	26,825	(41)	26,784	31,927	25,048	25,694	26,228	26,796
Other								
Office supplies and expenses	2,804	-	2,804	2,762	2,249	2,307	2,516	2,520
Professional services	9,494	(540)	8,954	14,408	6,662	8,846	9,112	8,825
Insurance	2,607	-	2,607	2,508	2,530	3,038	3,345	3,425
Equipment rentals	3,066	-	3,066	4,218	4,197	3,591	3,749	3,746
Travel	3,717	(500)	3,217	3,250	1,984	2,442	2,757	2,759
Miscellaneous expenses	5,654	-	5,654	5,789	4,974	5,643	5,784	5,867
Building rental and maintenance	1,217	-	1,217	1,497	1,109	1,077	1,100	1,100
Transportation	2,245	-	2,245	1,649	856	959	1,164	1,274
Customer costs	118	-	118	253	126	118	118	118
Total Other	30,922	(1,040)	29,882	36,334	24,687	28,021	29,645	29,634
Cost Allocations	(7,066)	(118)	(7,184)	(7,906)	(3,370)	(948)	1,235	2,073
Total operating costs	139,569	(6,832)	132,737	150,921	123,912	134,341	142,377	145,333

Chapter 3 - Schedule X

Total Operating Expenses by Functional Area

Newfoundland and Labrador Hydro
Total Operating Expenses by Functional Area
$ thousands

	2015 TY	2015 GRA Order	2015 Approved TY	2015 Actual	2016 Actual	2017 Forecast	2018 Test Year	2019 Test Year
Operations								
Transmission & Distribution & NLSO	54,920		54,920	59,718	47,495	46,168	46,999	47,605
Production	41,143		41,143	46,372	41,526	41,500	43,253	43,742
Engineering Services	4,176		4,176	3,772	2,424	4,069	4,591	4,964
Information & Operations Technology	7,312		7,312	7,163	6,399	8,142	9,633	11,240
Total Operations	107,551		107,551	117,025	97,844	99,879	104,476	107,551
General and Administration								
Executive Leadership	1,868		1,868	2,537	1,909	2,771	2,793	2,859
Financial Services	8,584		8,584	9,819	6,084	10,118	10,970	11,199
Business System Fee	-		-	-	253	1,029	2,542	1,894
Corporate Services & Regulatory Affairs	21,566		21,566	24,282	17,822	20,544	21,596	21,830
Total Corporate Services	32,018	-	32,018	36,638	26,068	34,462	37,901	37,782
Adjustment – EFB[1]	-	-	-	(2,742)	-	-	-	-
GRA Order Disallowances[2]	-	(6,832)	(6,832)	-	-	-	-	-
Total Operating Costs	139,569	(6,832)	132,737	150,921	123,912	134,341	142,377	145,333

1. The EFB adjustment was not allocated by Division.
2. Hydro did not allocate the disallowance noted in Order No. P.U. 49(2016) by Functional department.

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Chapter 4 Finance

4.1 Overview

In accordance with section 80 of the *Public Utilities Act* and section 3(a)(iii) of the *Electrical Power Control Act, 1994,* rates charged by Newfoundland and Labrador Hydro (Hydro) should provide the Company with the opportunity to earn a fair, just, and reasonable rate of return.[1] Sound financial performance is necessary to ensure Hydro's ability to deliver least cost, reliable electrical service to its customers.

Hydro's current base rates were last set effective July 1, 2017, based on a 2015 Test Year. These existing rates will result in a 2018 and 2019 return on rate base of 3.84% and 3.31%, respectively,[2] which is below Hydro's approved return on rate base of 6.61% for rate making purposes.[3] Hydro's revenue requirement is the sum of the return on rate base and other reasonable costs including operating costs, fuels, power purchases, and depreciation. Hydro's current general rate application (GRA) uses a 2018 and 2019 Test Year for determination of revenue requirement. The proposed rate of return on rate base for the 2018 and 2019 Test Years of 5.73% and 5.68%, respectively, is based on an embedded cost of debt of 5.34% and 5.25%, respectively, for the 2018 and 2019 Test Years,[4] and a return on equity (ROE) of 8.5% for the 2018 and 2019 Test Years.[5]

Revenue requirements for the 2015, 2018, and 2019 Test Years are provided in Table 4-1.

[1] In Order in Council OC2009-063, Government directed that: i) in calculating the return on rate base for Hydro, the same rate of return on equity (ROE) would be set for Hydro as was last set for Newfoundland Power Inc. (Newfoundland Power); ii) Hydro would earn ROE on its entire rate base, including amounts related to its rural assets; and iii) Hydro would be permitted to have a proportion of equity in its capital structure up to a maximum of the same as is approved for Newfoundland Power.
[2] Please refer to Schedule 4-III.
[3] Allowable range of rate of return on rate base is 6.41% to 6.81%.
[4] Please refer to Schedule 4-IV.
[5] Return on equity of 8.5% is the same ROE as was last set for Newfoundland Power in Order No. P.U. 18(2016).

Table 4-1 Revenue Requirement[6] ($ millions)

Component	2015 TY[7 8]	2018 TY	2019 TY	Change in 2018 TY vs. 2015 TY	Change in 2019 TY vs. 2015 TY
Revenue from Energy Sales	564.0	671.6	691.3	107.6	127.3
Generation Demand Cost Recovery	1.4	1.4	1.4		-
Fuel Rider[9]	39.1	-	-	(39.1)	(39.1)
Revenue Requirement	**604.5**	**673.0**	**692.7**	**68.5**	**88.2**

Incremental revenue requirement for the 2019 Test Year is provided in Figure 4-1. The primary drivers of the $88.2 million increase in revenue requirement from the 2015 Test Year are capital investment,[10] and fuels and other.[11] These increases are partially offset by a lower weighted average cost of capital (WACC) due to lower cost of debt and changes in capital structure.[12]

[6] Please refer to Schedule 4-I.
[7] 2015 Test Year comparatives as filed in Hydro's 2013 GRA Compliance Filing, filed January 27, 2017, as per Board Order No. 49(2016), Exhibit 2 – Computation of Revenue Requirements Appendix B – 2015 Finance Schedules (Rate Setting).
[8] 2015 Revenue Requirement has been restated as filed in Hydro's 2013 GRA Compliance Filing Exhibit 2, p. B-1 and Exhibit 13 Schedule 1.1, page 1.
[9] 2015 Test Year revenue requirement includes the forecast recovery from the fuel rider currently reflected in customer rates, as approved by the Board of Commissioners of Public Utilities (the Board) in Order No. P.U.22(2017).
[10] Capital investments of $66.0 million is comprised of depreciation of $28.6 million (Section 4.2.3) and return of $37.4 million (Section 4.5).
[11] Fuel and Other of $22.2 million is comprised of fuel costs of $28.5 million (Section 4.2.1) operating costs of $12.6 million (Section 4.2.5) and Other costs of $3.0 million. This is partially mitigated by a reduction in return of $21.9 million due to a decrease in weighted average cost of capital (Section 4.5).
[12] Please refer to Table 4-9 for additional information on Hydro's weighted average cost of capital.

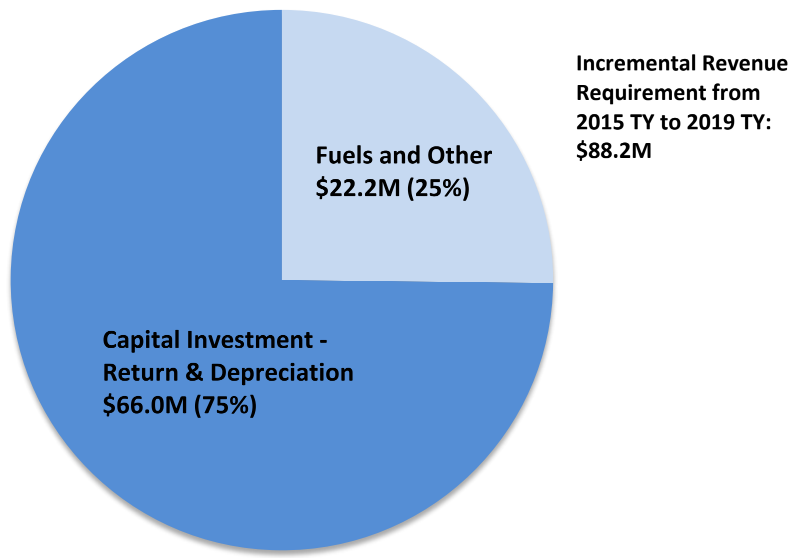

Figure 4-1 Incremental Revenue Requirement 2015 Test Year vs. 2019 Test Year

4.2 2018 Test Year and 2019 Test Year Revenue Requirement

The components of the 2018 and 2019 Test Year revenue requirements are provided in Table 4-2.

Table 4-2 Summary of Revenue Requirement[13] ($ millions)

Component	2015 TY	2018 TY	2019 TY
Fuels	226.6	250.2	255.2
Power Purchases	62.8	65.8	67.4
Operating Costs	132.7	142.4	145.3
Depreciation, CIAC, and Other	66.9	87.1	92.5
Other Revenue	(2.5)	(2.1)	(2.1)
Return on Rate Base	118.0	129.6	134.4
Revenue Requirement	**604.5**	**673.0**	**692.7**

4.2.1 Fuel Costs

Fuel Costs include the cost of No. 6 fuel used at the Holyrood Thermal Generating Station (Holyrood), fuel for Hydro's gas turbines, and diesel generator fuel. The 2018 Test Year fuel cost

[13] Please refer to Schedule 4-I.

of $250.2 million is $23.6 million higher than the 2015 Test Year cost of $226.6 million.[14] The 2019 Test Year fuel costs of $255.2 million are $5.0 million higher than those for the 2018 Test Year. The components of the Fuel Costs category are provided in Table 4-3. The primary driver of the increase is the forecast increase in No. 6 fuel costs.

Table 4-3 Fuel Costs ($ millions)

	2015 TY	**2018 TY**	**2019 TY**
Test Year No. 6 fuel	166.0	217.9	220.7
Fuel Rider Recovery	39.1	-	-
Total No. 6 Fuel	**205.1**	**217.9**	**220.7**
Diesel and Gas Turbine	21.5	32.3	34.5
Total Fuel	**226.6**	**250.2**	**255.2**

No. 6 fuel

No. 6 fuel expense[15] in the 2018 Test Year of $217.9 million is $12.8 million higher than the 2015 Test Year cost of $205.1 million. Fuel cost increased from an average of $79.58 per barrel[16] in the 2015 Test Year to $86.41 in the 2018 Test Year, resulting in an increase of approximately $17.2 million in fuel costs. This increase was offset by a reduction of 55,539 barrels from 2,577,657 in the 2015 Test Year to 2,522,118 in the 2018 Test Year, resulting in a decrease of $4.4 million in costs.

In the 2019 Test Year, No. 6 fuel expenses of $220.7 million is $2.8 million higher than that of the 2018 Test Year. The forecast cost increased from an average of $86.41 per barrel[17] in the 2018 Test Year to $87.11 per barrel in the 2019 Test Year, resulting in an increase of $1.8 million. In addition, the number of barrels forecast to be used in 2019 increased by 11,511 from 2,522,118 in the 2018 Test Year to 2,533,629, resulting in additional fuel costs of $1.0 million.

[14] 2015 Test Year revenue requirement includes the forecast recovery from the fuel rider currently reflected in customer rates, as approved by the Board in Order No. P.U.22(2017).

[15] Fuel expense is priced at the weighted average cost of inventory.

[16] 2015 Test Year fuel cost per barrel of $64.41 plus forecast fuel rider recovery of $15.17 per barrel ($39.1million/2,577,657 barrels).

[17] The forecast cost of No. 6 fuel is expressed in Canadian dollars.

Diesel and Gas Turbine fuel

In the 2018 Test Year, diesel and gas turbine fuel expenses of $32.3 million is $10.8 million higher than the 2015 Test Year. This increase is primarily due to a volume increase of $9.4 million (related to increased usage of the Holyrood gas turbine and Hardwoods gas turbine), which is offset by $0.8 million due to reduced fuel prices. Also contributing to the increased fuel cost is an increase in the costs of diesel fuel from $1.01/litre in the 2015 Test Year to $1.15/litre in the 2018 Test Year which results in an increase of $2.5 million. The remaining variance of $0.3 million is related to changes in the remaining units on the Island and Labrador Interconnected systems.

In the 2019 Test Year, diesel and gas turbine fuel expenses of $34.5 million are $2.2 million higher than those of the 2018 Test Year due to increased diesel costs of $1.4 million and increased gas turbine (Holyrood gas turbine and Hardwoods gas turbine) fuel expenses of $0.7 million due to fuel price increases. The cost of diesel fuel in the 2019 Test Year is forecast to be $1.23/litre, compared to $1.15/litre in the 2018 Test Year. The remaining variance of $0.1 million is related to changes in the remaining units on the Island and Labrador Interconnected systems.

4.2.2 Power Purchases

Power purchases include costs of supply from wind, Exploits Generation, and other sources as outlined in Table 4-4.

Table 4-4 Power Purchases ($ millions)

	2015 TY	2018 TY	2019 TY
Exploits Generation[18]	31.0	30.2	30.3
Wind	12.7	12.9	14.0
Capacity Assistance	2.1	3.1	3.1
Other	17.0	19.6	20.0
Total Power Purchases	**62.8**	**65.8**	**67.4**

[18] Includes the Star Lake generating facility

In the 2018 Test Year, power purchases of $65.8 million are $3.0 million higher than the 2015 Test Year primarily due to an increase in production at the Corner Brook Pulp and Paper Co-generation Facility, which is included in Other. In the 2019 Test Year, power purchases of $67.4 million are $1.6 million higher than the 2018 Test Year, mainly due to changes in costs associated with Wind purchases primarily due to the conclusion of Eco Energy rebates from the Federal government.

4.2.3 Depreciation, Contributions in Aid of Construction, and Other

The components of Depreciation, Contributions in Aid of Construction (CIAC), and Other costs are provided in Table 4-5.

Table 4-5 Depreciation, CIAC, and Other ($ millions)

	2015 TY	2018 TY	2019 TY
Depreciation	64.1	87.9	93.2
CIAC Amortization	(0.8)	(1.6)	(1.7)
Other Income and Expense	4.1	2.1	2.1
ARO Accretion[19]	0.7	0.3	0.3
Capital Asset Cost of Service Exclusions[20]	(1.2)	(1.6)	(1.4)
Depreciation, CIAC and Other	**66.9**	**87.1**	**92.5**

In the 2018 Test Year, Depreciation, CIAC, and Other costs of $87.1 million are $20.2 million higher than the 2015 Test Year. The primary drivers of this increase are:

- an increase in depreciation of $23.2 million associated with capital additions of approximately $753.7 million since the 2015 Test Year; [21] and
- an increase of $2.1 million in other costs related to an inventory allowance associated with Holyrood;[22]

[19] Accretion of cost associated with Asset Retirement Obligations (ARO) for the Holyrood Thermal Generating Station and polychlorinated biphenyls (PCBs) obligations.
[20] Capital asset cost of service exclusions is the reduction of depreciation for capital assets that have been excluded from recovery in rate base.
[21] Capital Additions for the period of 2016 (Actuals) to 2018 Test Year total $786.5 million, less Contributions in Aid of Construction of $32.8 million.
[22] Please refer to Section 4.35.

partially offset by:

- a reduction of $2.5 million associated with the new depreciation study[23] as outlined in Section 4.6.1; and
- a reduction of $2.6 million associated with the asset retirement obligation at Holyrood.[24]

In the 2019 Test Year, Depreciation, CIAC, and Other costs of $92.5 million are $5.4 million higher than the 2018 Test Year. The driver is an increase in depreciation associated with capital additions of approximately $168.3 million.[25]

4.2.4 Other Revenue

The components of Other Revenue are provided in Table 4-6.

Table 4-6 Other Revenue ($ millions)

	2015 TY	2018 TY	2019 TY
Pole Attachment Revenue	1.6	1.6	1.6
Sundry	0.9	0.5	0.5
Other Revenue	**2.5**	**2.1**	**2.1**

In each of the 2018 and 2019 Test Years, Other Revenue decreased by approximately $0.4 million in comparison to the 2015 Test Year. The primary driver is a reduction in sundry revenue which includes items such as tower rentals to communications companies.

4.2.5 Operating Costs

Operating costs includes labour and other costs associated with the operations of Hydro. Operating costs in the 2018 Test Year of $142.4 million are $9.7 million higher than the 2015

[23] Hydro engaged Concentric Advisors to conduct a new depreciation study relating to plant in service as of December 31, 2015. Please refer to Section 4.6.1 and Exhibit 11.

[24] Please refer to Exhibit 8 for the Holyrood Decommissioning Study. The assumptions surrounding the future use of the Holyrood site has been updated which resulted in a change to the estimated asset retirement obligation cost estimate.

[25] The 2019 Test Year includes capital additions of $168.7 million less contributions in aid of construction of $0.4 million.

Test Year. In the 2019 Test Year, operating costs of $145.3 million have increased by $2.9 million over the 2018 Test Year. Additional information on Operating Costs is contained in Chapter 3, Section 3.7.

4.3 Average Rate Base

The components of average rate base are provided in Table 4-7.

Table 4-7 Average Rate Base[26] ($ millions)

	2015 TY	2018 TY	2019 TY
Capital Assets - Average	1,623.6	2,077.6	2,185.4
Deductions:			
Average Capital Assets Excluded from Rate Base	(10.7)	(8.8)	(6.4)
Total Average Capital Assets in Rate Base	**1,612.9**	**2,068.8**	**2,179.0**
Other Components of Rate Base			
Working Capital Allowance	7.0	2.8	2.3
Fuel Inventory	47.4	76.5	74.4
Materials and Supplies	27.4	33.0	32.9
Deferred Charges	90.7	82.0	75.9
Additions to Rate Base	**172.5**	**194.3**	**185.5**
Average Rate Base	**1,785.4**	**2,263.1**	**2,364.5**

In the 2018 Test Year, the average rate base of $2,263.1 million is $477.7 million higher than the 2015 Test Year. In the 2019 Test Year, the average rate base of $2,364.5 million is $101.4 million higher than the 2018 Test Year.

4.3.1 Capital Assets

In the 2018 Test Year, average capital assets of $2,068.8 million are $455.9 million higher than the 2015 Test Year. The increase is primarily due to capital additions for the period from 2016 to the 2018 Test Year. Major additions include the 230 kV line from Bay d'Espoir to Western Avalon ($291.7 million), circuit breaker upgrades ($36.9 million), 230 kV line from Soldier's

[26] Please refer to Schedule 4-II, page 5 of 9

Pond to Hardwoods ($26.6 million), additional transmission investment to serve Happy Valley ($23.5 million), and refurbishment of Bay d'Espoir penstocks ($15.6 million).

In the 2019 Test Year, average capital assets of $2,179.0 million are $110.2 million higher than the 2018 Test Year as a result of capital additions.

4.3.2 Working Capital Allowance

Hydro's working capital allowance reflects the average amount of capital provided by investors to finance operations between the time expenditures are made to provide service to customers and the time payment is received from customers for that service. During 2016, Hydro engaged Christensen Associates Energy Consulting (CA Energy) to review its working capital methodology.[27] The review resulted in no changes to the existing methodology. A summary of working capital allowance is provided in Table 4-8.

Table 4-8 Working Capital Allowance ($ millions)

	2015 TY	2018 TY	2019 TY
Working Capital Factor:			
Revenue Lag Days	40.2	38.5	38.5
Expense Lag Days	23.3	28.8	28.7
Net Lag Days	16.9	9.7	9.8
Working Capital Factor % (Net Lag / 365 Days)	4.6%	2.7%	2.7%
Working Capital Allowance ($ millions)**:**			
Total Cash Operating Expenses	202.8	208.2	212.8
Working Capital Factor %	4.6%	2.7%	2.7%
Working Capital Allowance	9.4	5.6	5.7
HST Adjustment	(2.4)	(2.8)	(3.4)
Total Working Capital Allowance	**7.0**	**2.8**	**2.3**

[27] Please refer to Exhibit 9 for Cash Working Capital Review.

In the 2018 Test Year, the working capital allowance of $2.8 million is $4.2 million less that the 2015 Test Year due to changes in the net lag number of days. In the 2019 Test Year, working capital allowance is $0.5 million less than the 2018 Test Year.

4.3.3 Fuel Inventory

Fuel inventory is comprised of a thirteen month average of No. 6 fuel, diesel, and gas turbine fuel inventories. The drivers for the changes in average fuel for the 2018, and 2019 Test Years from the 2015 Test Year is both volume and price per barrel. The average purchase price[28] of No. 6 fuel in the 2015 Test Year was $64.41/bbl, the forecast price in the 2018 Test Year is $86.68/bbl, and $87.80/bbl in the 2019 Test Year.

4.3.4 Materials and Supplies

Materials and Supplies include consumables, inventory, and critical spares that are used by Hydro for construction and maintenance of operational assets and equipment. In the 2018 Test Year, material and supplies of $33.0 million is $5.6 million higher than the 2015 Test Year. In the 2019 Test Year, materials and supplies of $32.9 million is $0.1 million less than the 2018 Test Year.

4.3.5 Deferred Charges and Proposed Deferral Accounts

Deferred Charges represent expenses incurred by Hydro that are deferred and subsequently amortized and/or recovered over a defined period of time, as approved by the Board. Please refer to Schedule 4-V for the 2018 and 2019 Test Years, respectively.[29] Schedule 4-V includes previously approved deferrals as well as the proposed deferrals outlined below.

[28] Please refer to Schedule 3-VII for fuel purchase price.

[29] For the purposes of the 2018 and 2019 Test Years, Hydro has assumed that Phase II, Isolated Systems Supply Costs, Energy Supply Costs Deferral, the Holyrood Conversion Deferral, and the deferrals proposed in this Application, are approved for inclusion in rate base.

GRA Hearing Costs

Hydro is forecast to incur approximately $1.2 million in 2018 in external regulatory costs with respect to the current Application. Hydro is proposing to defer and amortize these costs over a three year period commencing in 2018 consistent with past regulatory practice of the Board.[30]

Cost of Service Hearing Costs

Hydro is forecast to incur approximately $0.5 million in 2018 in external regulatory costs with respect to a cost of service methodology review hearing.[31] Hydro is proposing to defer up to $0.5 million and amortize these costs over a three year period commencing in 2018.

Holyrood Inventory Allowance

Holyrood is currently scheduled to be converted to synchronous condenser mode by March 31, 2021. As of December 31, 2016, Hydro had a $10.1 million inventory of spare parts to service the plant; however, once Holyrood is converted to synchronous condenser mode, an estimated $6.8 million of inventory will no longer be required. In preparation for this, Hydro is proposing to record an inventory allowance from January 1, 2018 until March 31, 2021, and has included $2.1 million in each of the 2018 and 2019 Test Year revenue requirements.

2018 Revenue Deficiency

Hydro has proposed interim rates be approved effective January 1, 2018, prior to the approval of final rates.[32] Interim rates will provide Hydro with partial recovery of costs, resulting in a shortfall in revenue requirement of $22.6 million in 2018. Hydro proposes to defer this amount, include the balance in rate base,[33] and recover the balance over 20 months commencing

[30] The Board has allowed recovery of Application costs over a three year period with the most recent approval outlined in Board Order No. P.U.49(2016).
[31] Please refer to Chapter 5: Rates and Regulations for more information on the timing of Hydro's cost of service methodology review.
[32] Please refer to Chapter 5: Rates and Regulations, Section 5.4.1.
[33] This is consistent with past regulatory practice of the Board with respect to Hydro's 2014 Revenue Deficiency. See Order No. P.U.14(2017).

January 1, 2019, and ending August 31, 2020. This proposal is further explained in Chapter 5: Rates and Regulations.

4.3.6 Average Rate Base Methodology

In preparation for the GRA, Hydro engaged CA Energy to review the practices used by other utilities to establish rate base and provide recommendations or changes, if required, to Hydro's average rate base methodology.[34] CA Energy recommended that Hydro continue to use beginning-of-year and end-of-year averaging for capital assets in service and 13-month averages for fuel, materials and supplies, and deferred charges. In addition, CA Energy recommended that significant capital additions which increase the cost of service systems' average rate base be included in both the opening and closing rate base for rate setting purposes.[35] There is no impact on the GRA as a result of this recommendation. CA Energy's report on this matter is attached as Exhibit 10. Hydro proposes that the recommendations in the Average Rate Base Methodology Review be approved.

4.4 Return and Capital Structure

Return for Hydro is a function of the average rate base and the weighted average cost of capital.

4.4.1 Weighted Average Cost of Capital

Hydro's weighted average cost of capital for the 2018 and 2019 Test Years is 5.73% and 5.68%, respectively, compared to 6.61% in the 2015 Test Year as provided in Table 4-9.[36]

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[34] Please refer to Exhibit 10 for Hydro's Average Rate Base Methodology review.

[35] This approach is consistent the Board's direction regarding the inclusion in rate base of the Holyrood gas turbine in Order P.U. 49(2016).

[36] Please refer to Schedule 4-II, page 4.

Table 4-9 Weighted Average Cost of Capital

	2015 TY	2018 TY	2019 TY
Proportion of capital structure:			
Debt	74.23%	77.72%	77.01%
Asset Retirement Obligation [37]	0.62%	0.62%	0.58%
Employee Future Benefit [38]	3.92%	3.09%	3.09%
Equity	21.23%	18.57%	19.32%
Total Average Capital Structure	100.00%	100.00%	100.00%
Embedded cost of debt	6.47%	5.34%	5.25%
Return on Equity	8.50%	8.50%	8.50%
Weighted average cost of debt[39]	4.80%	4.15%	4.04%
Weighted average cost of equity[40]	1.81%	1.58%	1.64%
Weighted average cost of capital	**6.61%**	**5.73%**	**5.68%**

The reduction in weighted average cost of capital results in a decrease in return on rate base of $21.9 million from the 2015 Test Year to the 2019 Test Year. This reduction is due to a decrease in the cost of debt from 6.47% in the 2015 Test Year to 5.25%, which results in a reduction of $21.5 million and a reduced equity component in the capital structure, which resulted in a decrease in return of $0.4 million. The rate of return on equity has remained constant at 8.5% from 2016 to the 2019 Test Years.[41]

Cost of Debt

Table 4-10 provides Hydro's average debt, finance charges, and embedded cost of debt for the 2015, 2018, and 2019 Test Years, respectively.[42]

[37] This item has zero cost in the capital structure.
[38] This item has zero cost in the capital structure.
[39] Weighted average cost of debt = debt x embedded cost of debt
[40] Weighted average cost of equity = equity x return on equity
[41] In compliance with OC2009-063.
[42] Please refer to Schedule 4-IV.

Table 4-10 Embedded Cost of Debt ($ millions)

	2015 TY	2018 TY	2019 TY
Average Debt	1,316.8	1,790.6	1,855.4
Finance Charges [43]	85.2	95.6	97.4
Embedded Cost of Debt	**6.47%**	**5.34%**	**5.25%**

Hydro's increase in average debt from the 2015 Test Year to the 2019 Test Year is primarily driven by its capital additions and the funding requirements associated with the Rate Stabilization Plan refund that occurred in 2017. The average cost of debt is forecast to decline from the 2015 Test Year to the 2019 Test Year. This reflects lower average coupon rates on debt issuances and the retirement of higher rate, maturing debt.

Capital Structure

As shown in Table 4-9, average equity decreased from 21.23% in the 2015 Test Year to 19.32% in the 2019 Test Year. Under existing rates, average equity would decrease to 16.6% in 2019.

4.5 Return on Rate Base

Return on rate base is provided in Table 4-11.[44]

[43] Please refer to Schedule 4-II, page 8.
[44] Please refer to Schedule 4-II, page 5.

Table 4-11 Return on Rate Base ($ millions)

	2015 TY	2018 TY	2019 TY
Average Rate Base[45]	1,785.4	2,263.1	2,364.5
Regulated Returns			
Net Interest[46]	89.5	93.3	94.9
Net Income[47]	28.5	36.3	39.5
Return on Rate Base	**118.0**	**129.6**	**134.4**
Rate of Return on Rate Base	**6.61%**	**5.73%**	**5.68%**
Allowable RORB Range (+/-0.20) [48]	6.41% to 6.81%	5.53% to 5.93%	5.48% to 5.88%

The increase in return of rate base of $16.4 million from the 2015 Test Year to the 2019 Test Year is primarily due to an increase of $37.4 million return on average capital assets[49] in rate base and $0.9 million due to an increase in other components of rate base.[50] This is partially mitigated by a reduction of return of $21.9 million due to a decrease in weighted average cost of capital.[51]

4.6 Other Matters

4.6.1 Depreciation Methodology

In preparation for this Application, Hydro engaged Concentric Advisors to conduct a depreciation study relating to plant in service as of December 31, 2015.[52] In addition, as directed by the Board in Order No. P.U. 40(2012), Hydro has also included a report on group accounting for selected groups of property.[53]

The recommendations from the depreciation study are:

- use of updated estimates of service lives of assets;

[45] Please see Table 4.7.
[46] Please refer to Schedule 4-II, page 8.
[47] Please refer to Schedule –II, page 5.
[48] The allowable range of return on rate base was approved in Board Order No. P.U. 22(2017).
[49] Please refer to Section 4.3.1.
[50] Please refer to Sections 4.3.2 to 4.3.6.
[51] Please refer to Section 4.4.1.
[52] Please refer to Exhibit 11 for the Depreciation Study.
[53] Please refer to Exhibit 11.

- use of Average Service Life Group procedure applied on a remaining life basis for assets acquired prior to 2015;
- use of Equal Life Group procedure applied on a remaining life basis for assets acquired in 2015 and after;
- inclusion of asset removal costs in depreciation rates; and
- inclusion of loss on asset disposal costs in depreciation rates.

The combined impact of these changes on revenue requirement for the 2018 and 2019 Test Years is a decrease of $2.5 million and $2.4 million, respectively. Hydro proposes that the recommendations in the depreciation study be approved for inclusion in the determination of customer rates.

4.6.2 Automatic Return on Equity Adjustment

In Order No. P.U. 49(2016), the Board directed Hydro to file a proposal in relation to an automatic adjustment mechanism for its target return on equity to reflect any future changes to Newfoundland Power's approved target return on equity for rate setting.[54] On June 30, 2017, Hydro filed a report with the Board outlining its proposal. By letter dated July 14, 2017, the Board advised Hydro that it would consider Hydro's proposal regarding the automatic return on equity adjustment as part of this Application.

In accordance with the Board's direction, Exhibit 12 to this Application provides Hydro's proposal with respect to an automatic return on equity adjustment. The report provides an overview of the proposed calculation of the adjustment to return on equity, allocation of the adjustment to various customers, required adjustment to customer rates to reflect the change in revenue requirement, and process-related matters required to implement the rate adjustment.

[54] Order No. P.U. 49(2016), page 24.

4.6.3 Excess Earnings Account

As per Board Order P.U. No. 49(2016), the Board ordered Hydro to file a revised excess earnings account definition to reflect a range of rate of return on rate base of +/- 20 basis points.

Hydro's proposed definition is:

Definition of Excess Earnings Account

This account shall be credited with excess earnings in the event the result of the following formula is greater than zero:

A – (B X C)

Where:

A = Actual return on rate base, calculated as net interest expense, plus net income, plus cost of service exclusions

B = Actual average rate base, December 31

C = Upper limit of return on rate base, defined as Test Year Return on Rate Base + 20 basis points

The disposition of any balance in the account is to be determined by the Board.

4.7 Hydro's Proposals

Hydro is requesting the Board approve the following proposals:

- The continued use of the working capital methodology recommended in the Cash Working Capital Review;
- The amortization and recovery from January 1, 2018 to December 31, 2020, of general rate application hearing costs in an amount of $1.2 million, at a rate of $0.4 million per year;
- The amortization and recovery from January 1, 2018 to December 31, 2020, of cost of service hearing costs in an amount of $0.5 million, at a rate of $0.17 million per year;
- The inclusion of an allowance of $2.1 million per year in revenue requirement in relation to inventory at Holyrood and the creation of an inventory allowance;

- Interim rates to provide interim relief effective January 1, 2018 until December 31, 2018, in advance of final rates and the deferral and recovery of the revenue deficiency resulting from interim rates through a rate rider over a twenty-month period;
- The average rate base methodology and recommendations in the Average Rate Base Methodology Study;
- The forecast capital structure for 2018 with a weighted average cost of capital of 5.73%;
- The forecast capital structure for 2019 with a weighted average cost of capital of 5.68%;
- The depreciation rates and methodologies recommended in the 2016 Depreciation Study;
- Hydro's proposal in relation to an adjustment mechanism for its target return on equity to reflect any future changes to Newfoundland Power's approved target return on equity;
- Hydro's proposed excess earnings account definition;
- For the purposes of calculation of the 2018 Test Year;
    - A 2018 Test Year revenue requirement of $673.0 million,
    - A 2018 forecast average rate base of $2,263.1 million, and
    - A rate of return on rate base of 5.73% in a range of 5.53% to 5.93%; and
- For the purposes of calculation of the 2019 Test Year;
    - A 2019 Test Year revenue requirement of $692.7 million,
    - A 2019 forecast average rate base of $2,364.5 million, and
    - A rate of return on rate base of 5.68% in a range of 5.48% to 5.88%.

Chapter 4 – Schedule I

Revenue Requirement Analysis

Newfoundland and Labrador Hydro
Revenue Requirement Analysis ($000s)

	Test Year 2015	Actual 2015	Actual 2016	Forecast 2017	Test Year 2018	Test year 2019	Variance from 2015 Test year to 2018 Test Year $	Variance from 2015 Test Year to 2019 Test Year $
Revenue requirement								
Energy sales	564,002	550,403	559,525	556,551	671,574	691,324	107,572	127,322
Generation Demand Cost Recovery	1,387	1,262	1,288	1,213	1,482	1,442	95	55
Fuel Rider[1]	39,141	-	-	-	-	-	(39,141)	(39,141)
Total revenue requirement	604,530	551,665	560,813	557,764	673,056	692,766	68,526	88,236
Expenses								
Operating expenses	132,737	150,921	123,912	134,341	142,377	145,333	9,640	12,596
Other Income and expense	4,074	(12,895)	(16,703)	4,360	2,081	2,081	(1,993)	(1,993)
Fuels[2]	226,605	220,359	210,950	179,623	250,232	255,157	23,627	28,552
Power Purchases	62,827	60,667	60,117	64,275	65,838	67,428	3,011	4,601
Depreciation	64,055	63,222	67,436	76,028	87,885	93,189	23,830	29,134
Accretion of asset retirement obligation	748	699	645	189	362	364	(386)	(384)
	491,046	482,973	446,357	458,816	548,775	563,552	57,729	72,506
Other Adjustments:								
CIAC Revenue	(825)	(356)	(773)	(1,847)	(1,618)	(1,658)	(793)	(833)
Other revenue	(2,508)	(1,825)	(1,863)	(2,068)	(2,088)	(2,109)	420	399
Compliance Adjustments [3]	-	(25,282)	(9,017)	-	-	-	-	-
Cost of service exclusions[4]	(1,177)	(1,303)	(1,919)	(1,315)	(1,644)	(1,439)	(467)	(262)
	486,536	454,207	432,785	453,586	543,425	558,346	56,889	71,810
Return on rate base	117,994	97,458	128,028	104,178	129,631	134,420	11,637	16,426
Average rate base	1,785,353	1,747,243	1,886,283	2,075,503	2,263,109	2,364,465		
Rate of return on rate base	6.61%	5.58%	6.79%	5.02%	5.73%	5.68%		

[1] 2015 Test Year Revenue Requirement includes the forecast recoveries of $39.1 million from the Fuel Rider currently reflected in customer rates as approved by the Board in order No. P.U. 22(2017).
[2] 2015 Test Year Fuel restated to include fuel rider.
[3] Adjustments in accordance with the Board's ruling on Hydro amended GRA in order No.P.U.22(2017)
[4] Depreciation on assets excluded from rate base.

Chapter 4 – Schedule II

Financial Results and Forecasts (Proposed Rates)

Newfoundland and Labrador Hydro
Financial Results and Forecasts (Proposed Rates)
Statement of Income and Retained Earnings ($000s)

		Test Year 2015	Actual 2015	Actual 2016	Forecast 2017	Test Year 2018	Test Year 2019
1	**Revenue**						
2	Energy sales	564,002	550,403	559,525	556,551	671,574	691,324
3	Generation Demand Cost Recovery	1,387	1,262	1,288	1,213	1,482	1,442
4	CIAC Revenue	825	356	773	1,847	1,618	1,658
5	Other revenue	2,508	1,825	1,863	2,068	2,088	2,109
6	**Total revenue**	568,722	553,846	563,449	561,679	676,762	696,533
7							
8	**Expenses**						
9	Operating expenses	132,737	150,921	123,912	134,341	142,377	145,333
10	Other Income and expense	4,074	(12,895)	(16,703)	4,360	2,081	2,081
11	Amortization of foreign exchange losses	2,157	2,157	2,157	2,157	2,157	2,157
12	Fuels[1]	187,464	220,359	210,950	179,623	250,232	255,157
13	Power purchases	62,827	60,667	60,117	64,275	65,838	67,428
14	Depreciation	64,055	63,222	67,436	76,028	87,885	93,189
15	Accretion of asset retirement obligation	748	699	645	189	362	364
16	Interest	87,296	94,654	95,721	71,324	94,817	96,833
17	**Total expenses**	541,358	579,784	544,235	532,297	645,749	662,542
18							
19	**Net income (loss) before compliance adjustments**	27,364	(25,938)	19,214	29,382	31,013	33,991
20	Compliance Adjustments	-	25,282	9,017	-	-	-
21	**Net Income (loss) after compliance adjustments**	27,364	(656)	28,231	29,382	31,013	33,991
22							
23	**Retained earnings**						
24	Balance at beginning of year	259,556	231,626	235,464	263,695	293,077	324,090
25	Opening adjustment - retained earnings[2]	-	4,494	-	-	-	-
26	Dividends	-	-	-	-	-	-
27	**Balance at end of year**	286,920	235,464	263,695	293,077	324,090	358,081

[1] Fuel Rider of $39.1 million excluded.
[2] Opening adjustment related to the calculation of employee future benefits.

Newfoundland and Labrador Hydro
Financial Results and forecasts (Proposed Rates)
Balance Sheet ($000s)

		Test Year 2015	Actual 2015	Actual 2016	Forecast 2017	Test Year 2018	Test Year 2019
1	**Assets**						
2	Current assets						
3	Cash and cash equivalents	12,113	3,959	3,025	-	-	-
4	Accounts receivable	174,278	82,669	95,561	68,808	81,800	88,960
5	Inventory	89,642	65,557	76,198	126,327	116,726	88,858
6	Prepaid expenses	3,366	4,336	3,765	4,015	4,082	4,092
8		279,399	156,521	178,549	199,150	202,608	181,910
9							
10	Property, plant, and equipment[1]	1,908,342	1,689,805	1,820,573	2,113,913	2,230,663	2,286,878
11	Sinking funds	238,850	242,592	266,985	203,446	220,442	238,113
12	Regulatory assets	69,856	152,189	180,718	79,259	87,702	71,186
13							
14	**Total assets**	2,496,447	2,241,107	2,446,825	2,595,768	2,741,415	2,778,087
15							
16	**Liabilities and shareholder equity**						
17	Current liabilities						
18	Promissory notes	-	97,000	435,000	234,954	129,361	148,219
19	Accounts payable and accrued liabilities	8,322	72,704	113,116	97,376	104,727	63,083
20	Accrued interest	23,868	28,751	27,107	22,207	26,229	26,229
21	Deferred credits	-	438	370	370	370	370
22	Due to (from) related parties	687	387	3,223	3,738	3,701	3,707
23	Promissory notes - non-regulated	(8,187)	(11,110)	(11,067)	(11,067)	(11,067)	(11,067)
24		24,690	188,170	567,749	347,578	253,321	230,541
25							
26	Deferred capital contribution[1]	18,860	18,255	32,173	33,467	32,593	31,324
27	Long-term debt	1,649,544	1,240,339	1,014,314	1,661,582	1,912,197	1,912,850
28	Regulatory liabilities	287,382	324,942	343,987	31,018	(13,317)	9,186
29	Asset retirement obligations	25,526	27,946	14,456	14,545	14,810	15,077
30	Employee future benefits[2]	97,230	81,924	80,907	84,963	88,102	91,356
31	Contributed capital	100,000	100,000	100,000	100,000	100,000	100,000
32	Shareholder's equity / retained earnings	286,920	235,464	263,695	293,077	324,090	358,081
33	Accumulated other comprehensive income	6,295	24,067	29,544	29,538	29,619	29,672
34							
35	**Total liabilities and shareholder's equity**	2,496,447	2,241,107	2,446,825	2,595,768	2,741,415	2,778,087

[1] Contributions for assets that are still under construction have been included in property, plant and equipment and excluded from deferred capital contributions.
[2] Please refer to Schedule 4-II, Page 7.

Newfoundland and Labrador Hydro
Financial Results and Forecasts (Proposed Rates)
Cash Flow ($000s)

		Test Year 2015	Actual 2015	Actual 2016	Forecast 2017	Test Year 2018	Test Year 2019
1	**Cash provided by (used in)**						
2	**Operating activities**						
3	Net income	27,364	(656)	28,231	29,382	31,013	33,991
4	Adjusted for items not involving cash flow						
5	Amortization	64,055	63,222	67,436	76,028	87,885	93,189
6	Asset retirement obligation and long term debt accretion	1,243	1,246	1,185	837	977	1,017
7	Amortization of deferred contributions	(825)	(356)	(773)	(1,848)	(1,618)	(1,659)
8	Employee future benefits	6,241	3,398	(1,017)	4,056	3,139	3,254
9	Other income and expense	1,904	3,246	6,598	3,637	-	-
10	Other	(13,185)	(13,638)	(12,570)	(10,574)	(10,381)	(11,085)
11		86,797	56,462	89,090	101,518	111,015	118,707
12	**Changes in non-cash balances**						
13	Accounts receivable	(74,929)	1,924	(12,930)	26,753	(12,992)	(7,160)
14	Inventory	(6,642)	19,938	(10,641)	(50,129)	9,601	27,868
15	Prepaid expenses	(24)	138	571	(250)	(67)	(10)
16	Regulatory assets	44,156	(45,466)	(28,529)	101,459	(8,443)	16,516
17	Regulatory liabilities	41,121	78,539	19,045	(312,969)	(44,335)	22,503
18	Accounts payable and accrued liabilities	(39,220)	(23,550)	40,412	(15,740)	7,351	(41,644)
19	Accrued interest	(3,600)	-	(1,644)	(4,900)	4,022	-
20	Due to related parties	274	1,976	2,836	515	(37)	6
21		47,933	89,961	98,210	(153,743)	66,115	136,786
22	**Financing activities**						
23	Increase in long-term debt	400,000	-	-	782,483	250,000	-
24	Decrease in deferred credits	-	(247)	(68)	-	-	-
25	Increase in deferred capital contributions	1,386	11,455	17,090	742	744	390
26	Long-term debt repayment	-	-	(225,100)	(135,881)	-	-
27	(Decrease) increase in promissory notes	(145,564)	39,647	338,043	(200,046)	(105,593)	18,858
28		255,822	50,855	129,965	447,298	145,151	19,248
29	**Investing activities**						
30	Additions to property, plant and equipment	(283,492)	(136,625)	(220,959)	(370,937)	(204,616)	(149,384)
31	(Increase) decrease in sinking funds	(8,150)	(8,150)	(8,150)	74,356	(6,650)	(6,650)
32		(291,642)	(144,775)	(229,109)	(296,581)	(211,266)	(156,034)
33							
34	**Net increase (decrease) in cash**	12,113	(3,959)	(934)	(3,025)	-	-
35							
36	**Cash position, beginning of year**	-	7,918	3,959	3,025	-	-
37							
38	**Cash position, end of year**	12,113	3,959	3,025	-	-	-

Newfoundland and Labrador Hydro
Financial Results and Forecasts (Proposed Rates)
Capital Structure ($000s)

		Test Year 2015	Actual 2015	Actual 2016	Forecast 2017	Test Year 2018	Test Year 2019
1	**Regulated capital structure**						
2	Long-term debt	1,649,544	1,240,339	1,014,314	1,661,582	1,912,197	1,912,850
3	Promissory notes	-	97,000	435,000	234,954	129,361	148,219
4	Promissory notes - related party	-	-	-	-	-	-
5	less: sinking funds	(238,850)	(242,592)	(266,985)	(203,446)	(220,442)	(238,113)
6	add: mark to market of sinking funds	31,071	41,150	44,902	43,329	43,329	43,329
7		1,441,765	1,135,897	1,227,231	1,736,419	1,864,445	1,866,285
8	Cost of service exclusions	-	-	-	-	-	-
9	Non-regulated debt pool	(8,187)	(11,110)	(11,067)	(11,067)	(11,067)	(11,067)
10	Net regulated debt	1,433,578	1,124,787	1,216,164	1,725,352	1,853,378	1,855,218
11	Funded Asset retirement obligation[1]	12,247	13,459	14,815	14,300	14,082	13,983
12	Funded employee future benefits balance [2]	72,454	64,709	65,509	69,558	72,778	76,085
13	Contributed capital	100,000	100,000	100,000	100,000	100,000	100,000
14	Retained earnings cost of service exclusions	2,154	8,125	12,628	16,317	21,641	27,207
15	Retained earnings	286,920	235,464	263,695	293,077	324,090	358,081
16	**Total**	1,907,353	1,546,544	1,672,811	2,218,604	2,385,969	2,430,573
17							
18	**Regulated capital structure (%)**						
19	Debt	75.16%	72.73%	72.70%	77.77%	77.68%	76.33%
20	Asset retirement obligation	0.64%	0.87%	0.89%	0.64%	0.59%	0.58%
21	Employee future benefits	3.80%	4.18%	3.92%	3.14%	3.05%	3.13%
22	Equity	20.40%	22.22%	22.50%	18.45%	18.68%	19.97%
23	**Total**	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
24							
25	**Regulated average capital structure (%)**						
26	Debt	74.23%	72.77%	72.72%	75.23%	77.72%	77.01%
27	Asset retirement obligation	0.62%	0.78%	0.88%	0.77%	0.62%	0.58%
28	Employee future benefits	3.92%	4.30%	4.05%	3.53%	3.09%	3.09%
29	Equity	21.23%	22.16%	22.36%	20.47%	18.57%	19.32%
30	**Total**	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
31							
32	**Weighted average cost of capital (WACC)**						
33	Embedded cost of debt	6.47%	6.79%	6.30%	5.26%	5.34%	5.25%
34	Asset retirement obligation	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
35	Employee future benefits	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
36	Equity	8.50%	8.80%	8.50%	8.50%	8.50%	8.50%
37	**WACC**	6.61%	6.89%	6.48%	5.69%	5.73%	5.68%

[1] Please refer to Schedule 4-II, Page 9.
[2] Please refer to Schedule 4-II, Page 7.

Newfoundland and Labrador Hydro
Financial Results and Forecasts (Proposed Rates)
Rate of Return ($000s)

	Test Year 2015	Actual 2015	Actual 2016	Forecast 2017	Test Year 2018	Test Year 2019
1 **Property, plant, and equipment**	1,908,342	1,689,805	1,820,573	2,113,913	2,230,663	2,286,878
2 add: accumulated depreciation	204,001	168,306	233,720	308,582	389,021	476,625
3 less: work in progress [1]	(240,977)	(29,171)	(89,698)	(71,760)	(51,306)	(30,488)
4 **Capital assets in service**	1,871,366	1,828,940	1,964,595	2,350,735	2,568,379	2,733,014
5 less: asset retirement obligation	(12,169)	(14,381)	465	79	(307)	(693)
6 add: contributions in aid of construction [1]	(18,660)	(18,255)	(32,173)	(33,466)	(32,593)	(31,324)
7 less: accumulated depreciation	(204,001)	(168,306)	(233,720)	(308,582)	(389,021)	(476,625)
8 **Capital assets - current year**	1,636,536	1,627,998	1,699,166	2,008,765	2,146,457	2,224,372
9 **Capital assets - previous year**	1,610,437	1,468,388	1,627,998	1,699,166	2,008,765	2,146,457
10 Unadjusted capital assets - average	1,623,486	1,548,193	1,663,582	1,853,966	2,077,611	2,185,414
11 less: Average net assets excluded from rate base	(10,634)	(10,732)	(16,676)	(16,246)	(8,820)	(6,415)
12 **Capital assets - average**	1,612,852	1,537,461	1,646,906	1,837,720	2,068,791	2,178,999
13						
14 Working capital allowance	7,037	6,995	5,304	7,582	2,772	2,255
15 Fuel	47,398	44,052	35,473	67,287	76,472	74,369
16 Materials and supplies	27,402	29,279	32,146	33,135	33,034	32,884
17 Deferred charges [2]	90,665	129,456	166,454	129,780	82,041	75,958
18						
19 **Average rate base**	1,785,353	1,747,243	1,886,283	2,075,503	2,263,109	2,364,465
20						
21 Net Income [3]	27,364	(656)	28,231	29,382	31,013	33,991
22 add: Cost of service exclusions:						
23 Depreciation on Assets Excluded from Rate Base	1,177	1,303	1,919	1,315	1,644	1,439
24 Interest Cost of Service Exclusions [4]	-	2,752	2,584	2,374	3,680	4,127
25 Net Interest [5]	89,453	94,059	95,294	71,107	93,295	94,863
26 **Return on rate base**	117,994	97,458	128,028	104,178	129,631	134,420
27						
28 **Rate of return on rate base**	6.61%	5.58%	6.79%	5.02%	5.73%	5.68%

[1]Contributions for assets that are still under construction have been included in work in progress and excluded from contributions in aid of construction.
[2]Please refer to Schedule 4-V.
[3]Net Income has been updated for compliance adjustments. Refer to Schedule 4-II, Page 1.
[4]Interest exclusions are primarily the disallowed portion of the debt guarantee fee.
[5]Please refer to Schedule 4-II, Page 8.

Newfoundland and Labrador Hydro
Financial Results and Forecasts (Proposed Rates)
Rate Stabilization Plan ($000s)

		Test Year 2015	Actual 2015	Actual 2016	Forecast 2017	Test Year 2018	Test Year 2019
1	**Rate stabilization plan**						
2	Hydraulic	(47,862)	(56,458)	(37,018)	(595)	(446)	(335)
3	Utility	(60,639)	(70,887)	(68,977)	(18,098)	15,240	(5,141)
4	Industrial	703	474	(2,578)	2,101	922	731.00
5	Segregated Load Variation	(43,938)	(61,197)	(91,277)	-	-	-
6	Utility Surplus	(132,285)	(133,351)	(143,391)	(14,009)	64	68
7	Industrial Surplus	(3,054)	(3,130)	(389)	-	-	-
8	**Total**	(287,075)	(324,549)	(343,630)	(30,601)	15,780	(4,677)
9							
10	**Average fuel cost per barrel**	$ 64.41	$ 67.21	$ 46.40	$ 73.91	$ 86.41	$ 87.11

Newfoundland and Labrador Hydro
Financial Results and Forecasts (Proposed Rates)
Employee Future Benefits ($000s)

		Test Year 2015	Actual 2015	Actual 2016	Forecast 2017	Test Year 2018	Test Year 2019
1	**Employee future benefits**						
2	Balance at beginning of year	66,213	66,969	64,709	65,509	69,558	72,778
3	Current service	3,177	2,787	3,237	2,926	3,040	3,159
4	Interest	3,613	3,434	3,430	3,248	3,368	3,493
5	Amortization of actuarial losses	1,581	449	215	91	61	33
6	Amortization of past service costs	-	20	20	20	20	20
7	Prior period adjustments	-	(4,494)	-	-	-	-
8	Transfers	-	(2,064)	(3,075)	910	-	-
9	Benefits paid	(2,130)	(2,392)	(3,027)	(3,146)	(3,269)	(3,398)
10	**Funded employee future benefits balance** [1]	72,454	64,709	65,509	69,558	72,778	76,085
11	Opening adjustment - Other comprehensive income (OCI)	1,349	1,349	1,349	1,349	1,349	1,349
12	Actuarial losses amortized through OCI	5,554	4,692	4,692	4,692	4,692	4,692
13	Unamortized losses	17,873	29,290	9,357	9,364	9,283	9,230
14	Unamortized losses prior period OCI adjustment	-	(18,116)	-	-	-	-
15	**Employee future benefits** [2]	97,230	81,924	80,907	84,963	88,102	91,356

[1] Please refer to Schedule 4-II, Page 4.
[2] Please refer to Schedule 4-II, Page 2.

Newfoundland and Labrador Hydro
Financial Results and Forecasts (Proposed Rates)
Interest ($000s)

		Test Year 2015	Actual 2015	Actual 2016	Forecast 2017	Test Year 2018	Test Year 2019
1	**Interest**						
2	Long-term debt	95,325	84,525	82,431	81,200	99,330	100,215
3	Accretion of long-term debt	495	547	540	648	615	653
4	Amortization of foreign exchange losses	2,157	2,157	2,157	2,157	2,157	2,157
5	Debt guarantee fee	1,887	4,514	4,524	4,127	7,359	8,254
6	Interest cost of service exclusions[1]	-	(2,752)	(2,584)	(2,374)	(3,680)	(4,127)
7	Other interest	(1,230)	161	641	3,869	890	1,584
8	Interest on sinking fund	(13,413)	(13,450)	(13,952)	(12,295)	(11,057)	(11,331)
9	**Finance Charges[2]**	85,221	75,702	73,757	77,332	95,615	97,405
10	Interest on rate stabilization plan	15,190	21,723	25,505	7,573	(248)	(390)
11	Interest capitalized during construction	(10,958)	(3,366)	(3,968)	(13,798)	(2,072)	(2,152)
12	**Net Interest**	89,453	94,059	95,294	71,107	93,295	94,863
13	Amortization of foreign exchange losses[3]	(2,157)	(2,157)	(2,157)	(2,157)	(2,157)	(2,157)
14	Debt Guarantee Fee Exclusion	-	2,752	2,584	2,374	3,680	4,127
15	**Interest[4]**	87,296	94,654	95,721	71,324	94,817	96,833

[1] Interest exclusions are primarily the disallowed portion of the debt guarantee fee.
[2] Please refer to schedule 4-IV.
[3] Shown as Foreign Exchange on Schedule 4-II, page 1.
[4] Please refer to schedule 4-II, page 1.

Newfoundland and Labrador Hydro
Financial Results and Forecasts (Proposed Rates)
Funded Asset Retirement Obligation ($000s)

	Test Year 2015	Actual 2015	Actual 2016	Forecast 2017	Test Year 2018	Test Year 2019
1 **Funded asset retirement obligation:**						
2 Opening	9,798	10,283	13,459	14,815	14,300	14,082
3 Accretion	748	699	645	189	362	364
4 Depreciation	1,846	2,622	1,246	(386)	(345)	(345)
5 Asset retirement obligation disposed	(145)	(145)	(536)	(318)	(235)	(118)
6 **Ending** [1]	12,247	13,459	14,815	14,300	14,082	13,983

[1] Please refer to schedule 4-II, page 4.

Chapter 4 – Schedule III

Return on Rate Base (Existing Rates)

Newfoundland and Labrador Hydro
Return on Rate Base (Existing Rates)
($000s)

		Test Year 2015	Actual 2015	Actual 2016	Forecast 2017	Existing Rates 2018	Existing Rates 2019
1	**Revenue**						
2	Energy sales	564,002	550,403	559,525	556,551	557,806	558,860
3	Generation Demand Cost Recovery	1,387	1,262	1,288	1,213	1,210	1,210
4	CIAC Revenue	825	356	773	1,847	1,945	1,760
5	Other revenue	2,508	1,825	1,863	2,068	879	900
6	**Total revenue**	568,722	553,846	563,449	561,679	561,840	562,730
7							
8	**Expenses**						
9	Operating expenses	132,737	150,921	123,912	134,341	141,825	144,781
10	Other Income and expense	4,074	(12,895)	(16,703)	4,360	5,647	5,063
11	Amortization on foreign exchange losses	2,157	2,157	2,157	2,157	2,157	2,157
12	Fuels	187,464	220,359	210,950	179,623	177,766	177,455
13	Power purchases	62,827	60,667	60,117	64,275	65,838	67,428
14	Depreciation	64,055	63,222	67,436	76,028	85,045	90,667
15	Accretion of asset retirement obligation	748	699	645	189	362	364
16	Interest	87,296	94,654	95,721	71,324	93,907	97,824
17	**Total expenses**	541,358	579,784	544,235	532,297	572,547	585,739
18							
19	**Net income (loss) before compliance adjustments**	27,364	(25,938)	19,214	29,382	(10,707)	(23,009)
20	Compliance Adjustments	-	25,282	9,017	-	-	-
21	**Net Income (loss) after compliance adjustments**	27,364	(656)	28,231	29,382	(10,707)	(23,009)
22							
23							
24	Unadjusted return on regulated equity	27,364	(656)	28,231	29,382	(10,707)	(23,009)
25	add: Cost of service exclusions:						
26	Depreciation on Assets Excluded from Rate Base	1,177	1,303	1,919	1,315	1,361	1,297
27	Interest cost of service exclusions[1]	-	2,752	2,584	2,374	3,680	4,154
28	Net Interest	89,453	94,059	95,294	71,107	92,385	95,854
29	**Return on rate base**	117,994	97,458	128,028	104,178	86,719	78,296
30							
31	**Average rate base**	1,785,353	1,747,243	1,886,283	2,075,503	2,259,681	2,361,995
32							
33	**Rate of return on rate base**	6.61%	5.58%	6.79%	5.02%	3.84%	3.31%

[1]Interest exclusions are primarily the disallowed portion of the debt Guarantee fee.

Chapter 4 – Schedule IV

Embedded Cost of Debt

Newfoundland and Labrador Hydro
Embedded Cost of Debt
($000s)

	Series	Interest Rate	Year of Issue	Year of Maturity	Test Year 2015	Actual 2015	Actual 2016	Forecast 2017	Test year 2018	Test Year 2019
1	Series V	10.50%	1989	2014	-	300	200	200	200	200
2	Series X	10.25%	1992	2017	150,000	150,000	150,000			
3	Series Y	8.40%	1996	2026	300,000	300,000	300,000	300,000	300,000	300,000
4	Series AB	6.65%	2001	2031	300,000	300,000	300,000	300,000	300,000	300,000
5	Series AD	5.70%	2003	2033	125,000	125,000	125,000	125,000	125,000	125,000
6	Series AE	4.30%	2006	2016	225,000	225,000				
7	Series AF	3.60%	2014	2045	600,000	200,000	200,000	200,000	200,000	200,000
8	New Issuance - 2017	3.60%	2017	2045				300,000	300,000	300,000
9	New Issuance - 2017	3.40%	2017	2027				200,000	200,000	200,000
10	New Issuance - 2017	4.18%	2017	2047				300,000	300,000	300,000
11	New Issuance - 2018	4.25%	2018	2048					250,000	250,000
12										
13	Total debentures				1,700,000	1,300,300	1,075,200	1,725,200	1,975,200	1,975,200
14										
15	Promissory notes				-	97,000	435,000	234,954	129,361	148,219
16	Less:									
17	Sinking funds				(257,000)	(257,291)	(279,397)	(202,030)	(219,006)	(236,976)
18	Non-regulated debt pool				(8,187)	(11,110)	(11,067)	(11,067)	(11,067)	(11,067)
19	Unamortized debt discount and financing				(1,235)	(4,112)	(3,573)	(20,462)	(19,847)	(19,194)
20										
21	**Total debt**				1,433,578	1,124,787	1,216,163	1,726,595	1,854,641	1,856,182
22										
23	**Average debt**				1,316,766	1,115,446	1,170,475	1,471,379	1,790,618	1,855,412
24										
25					**Test year 2015**	**Actual 2015**	**Actual 2016**	**Forecast 2017**	**Test year 2018**	**Test Year 2019**
26	**Embedded cost of debt**									
27	Long-term debt				95,325	84,525	82,431	81,200	99,330	100,215
28	Accretion of long-term debt				495	547	540	648	615	653
29	Amortization of foreign exchange losses				2,157	2,157	2,157	2,157	2,157	2,157
30	Debt guarantee fee				1,887	4,514	4,524	4,127	7,359	8,254
31	Other interest				(1,230)	161	641	3,869	890	1,584
32	Interest on sinking fund				(13,413)	(13,450)	(13,952)	(12,295)	(11,057)	(11,331)
33					85,221	78,453	76,341	79,706	99,294	101,532
34	Less Cost of Service Exclusion[1]					(2,752)	(2,584)	(2,374)	(3,680)	(4,127)
35	Finance Charges				85,221	75,701	73,757	77,332	95,615	97,405
36										
37	**Embedded cost of debt**				6.47%	6.79%	6.30%	5.26%	5.34%	5.25%

[1] Interest exclusions are primarily the disallowed portion of the debt guarantee fee.

Chapter 4 – Schedule V

Summary of Deferred Charges

Newfoundland and Labrador Hydro
Summary of Deferred Charges ($000s)

		Jan. 1, 2018 Opening Balance	Additions	Dispositions	Amortization	Dec. 31, 2018 Ending Balance	Additions	Dispositions	Amortization	Dec. 31, 2019 Ending Balance
1	**Deferred Charges:**									
2										
3	**Existing**									
4	CDM	9,863.0	2,100.0	(1,200.0)	-	10,763.0	2,100.0	(1,200.0)	-	11,663.0
5	Phase II Hearing Costs	1,869.0	-	-	-	1,869.0	-	-	-	1,869.0
6	Isolated Systems Supply Cost	838.0		(838.0)	-	-		-	-	-
7	Energy Supply Costs Deferral	8,561.0	-	(8,561.0)	-	-	-	-	-	-
8	Holyrood Conversion	3,419.0		(3,419.0)	-	-		-	-	-
9	Holyrood Blackstart Diesel	3,130.0	-	-	(1,341.0)	1,789.0	-	-	(1,341.0)	448.0
10	Asset Disposal	368.0		-	(19.0)	349.0			(19.0)	330.0
11	Deferred Foreign Exchange - Inventory	(158.0)		-		(158.0)		-	-	(158.0)
12	Foreign Exchange	51,767.0	-	-	(2,157.0)	49,610.0	-	-	(2,157.0)	47,453.0
13	Deferred Power Purchase Deferral	(417.0)	-	-	36.0	(381.0)	-	-	36.0	(345.0)
14	Labrador RSP Refund	(398.0)	-	200.0	-	(198.0)	-	198.0	-	-
15										
16	**Proposed**									
17	GRA Hearing Costs	-	1,200.0	-	(400.0)	800.0	-	-	(400.0)	400.0
18	Cost of Service Hearing Costs	-	450.0	-	(150.0)	300.0	-	-	(150.0)	150.0
19	Holyrood Inventory Allowance	-	(2,082.0)	-	-	(2,082.0)	(2,082.0)	-	-	(4,164.0)
20	2018 Revenue Deficiency	-	22,578.0	-	-	22,578.0	-	(13,547.0)	-	9,031.0
21	**Total Deferred Charges**	**78,842.0**	**24,246.0**	**(13,818.0)**	**(4,031.0)**	**85,239.0**	**18.0**	**(14,549.0)**	**(4,031.0)**	**66,677.0**
22										
23	Current Year Opening	180,718.0				78,842.0				85,239.0
24	**Average Deferred Charges for Rate Base**	**129,780.0**				**82,040.5**				**75,958.0**

Chapter 5 – Rates and Regulations

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Chapter 5 Rates and Regulations

5.1 Overview

On the Island Interconnected System, Newfoundland and Labrador Hydro (Hydro) provides electricity service to Newfoundland Power Inc. (Newfoundland Power) and five Industrial Customers: Corner Brook Pulp and Paper Limited (CBPP); North Atlantic Refining Limited (NARL); Teck Resources Limited (Teck); Vale Newfoundland & Labrador Limited (Vale); and Praxair Canada Inc. (Praxair).[1] Hydro also serves approximately 22,900 Rural Customers at the retail level on the Island Interconnected System.

On the Labrador Interconnected System, Hydro serves approximately 11,200 Rural Customers and two Industrial Customers: the Iron Ore Company of Canada (IOC) and the Wabush Mines facility.[2] On the 21 isolated systems, including the L'Anse au Loup system, Hydro has approximately 4,500 Rural Customers.

To determine fair rates for its customers, Hydro prepares Cost of Service studies for five systems:

- Island Interconnected;
- Island Isolated;
- Labrador Isolated;
- L'Anse au Loup; and
- Labrador Interconnected.

Rates for these customers are grouped into the following classifications:

- Island Interconnected Utility (Newfoundland Power);
- Island Interconnected Industrial Customers;

[1] Teck Resources is in the process of closing. There is minimal load requirement for Teck reflected in the 2019 Test Year load forecast.

[2] Under the Labrador Industrial Rates Policy, the rate charged to Labrador Industrial Customers on the Labrador Interconnected System for transmission-related costs is regulated and generation supply to customers is non-regulated.

- Island Interconnected and L'Anse au Loup Rural Customers;
- Island and Labrador Isolated Rural Customers - Non-Government;
- Island and Labrador Isolated Rural Customers - Government;
- Labrador Interconnected Rural Customers; and
- Labrador Industrial Customers.

The Rates and Regulations evidence addresses the:

- Cost of Service Methodology Review;
- Proposed Cost of Service methodology for the current general rate application (GRA);
- Marginal Cost Outlook;
- Recovery of revenue requirement;
- Proposed Wholesale and Island Industrial rates;
- Proposed Rate Stabilization Plan (RSP) changes;
- Proposed rates for Hydro Rural Customers;
- Proposed Labrador Industrial Transmission rates; and
- Change in Test Year revenues based on both existing and proposed rates.

5.2 Cost of Service Methodology Review

5.2.1 General

For many years, incremental load growth on the Island Interconnected System has been supplied by the Holyrood Thermal Generating Station (Holyrood). The completion of the Muskrat Falls Project will result in a major change in the source of supply of electricity to the Island.[3] Upon the full commissioning of the Muskrat Falls Project, supply cost payments will commence under the Transmission Funding Agreement and Muskrat Falls Power Purchase Agreement, and Holyrood, as a generating station, will eventually be phased-out.

[3] The Muskrat Falls Project includes the Muskrat Falls generation, the Labrador-Island Link, and the Labrador Transmission Assets.

In June 2016, it was announced that the Muskrat Falls Project is behind schedule and that full commissioning is not expected until 2020. The delay in commissioning of the Muskrat Falls Project until 2020 removes the requirement for the costs of the Muskrat Falls Project to be recovered in 2018 or 2019 through Hydro's 2017 GRA filing.

5.2.2 Timing of Cost of Service Methodology Review

In its Amended 2013 GRA, Hydro proposed to conduct a Cost of Service Methodology review prior to its next GRA due to the material change in the forecast supply cost mix with the commissioning of the Muskrat Falls Project. The Settlement Agreements to the Amended 2013 GRA required Hydro to file a Cost of Service Methodology Review Report with the Board of Commissioners of Public Utilities (the Board) by March 31, 2016.[4]

The Parties also agreed that the generation credit agreement between Hydro and CBPP, which was approved on a pilot basis by the Board in Order No. P.U. 4(2012), would be reviewed in the cost of service review hearing.

In its Cost of Service Methodology Review report filed with the Board on March 31, 2016, Hydro assumed that supply costs from the Muskrat Falls Project would be reflected in its 2019 costs for the full year. However, due to the delay in the Muskrat Falls Project, Hydro proposed to delay the cost of service methodology hearing until after the 2017 GRA. By letter dated September 9, 2016, the Board approved the delay in conducting the Cost of Service Methodology Review. However, the Board indicated that certain cost of service issues, such as issues related to the methodology for calculating specifically assigned charges, could be, and should be, addressed in the usual course apart from the full cost of service methodology review. The Board also directed Hydro to advise of its plan for the full cost of service

[4] As agreed in the Supplemental Settlement Agreement to the Amended 2013 GRA dated September 28, 2015, the Cost of Service Methodology Review will include a review of: (i) all matters related to the functionalization, classification, and allocation of transmission and generation assets and power purchases (including the determination whether assets are specifically assigned and the allocation of costs to specifically assigned assets) and (ii) the approach to CDM cost allocation and recovery.

methodology review to reflect the inclusion of Muskrat Falls Project costs in its next general rate application.

Government direction (Order in Council (OC) 2013-343) requires near or full commissioning of the Muskrat Falls Project prior to Hydro being able to recover from customers the costs associated with the Labrador-Island Link (LIL), Labrador Transmission Assets (LTA), and Muskrat Falls generation. It is anticipated that Hydro will file an application in 2019 to provide the opportunity to recover the supply costs resulting from the full commissioning of the Muskrat Falls Project forecast for 2020. Hydro plans to file an application in the third quarter of 2018 to conduct a Cost of Service and Rate Design Methodology Review to determine the changes required to reflect the Labrador-Island interconnection. The reports filed by Hydro in 2015 and 2016 in accordance with the 2013 GRA Settlement Agreements on marginal costs, cost of service methodology, and rate design post Muskrat Falls Project commissioning will be considered by the Board in the proposed review process.[5] The results of the Board's decision on these matters will be reflected in Hydro's subsequent GRA filing planned for 2019.

5.2.3 Power Availability in Advance of Muskrat Falls Commissioning

For the period 2018 to 2020, Hydro is transitioning to the interconnection with the North American grid. During the transition period, the LIL and the Maritime Link (ML) will be available, providing an opportunity to reduce the use of costly Holyrood generation by using lower cost off-Island purchases in 2018, 2019 and 2020.

Hydro and its parent company, Nalcor Energy (Nalcor), will be expected to provide open access to its transmission facilities during the transition period. The provision of open access requires the implementation of a transmission tariff which conforms to universally-accepted reciprocity

[5] Hydro filed two reports with the Board on marginal costs reflecting the Labrador-Island interconnection. Part 1 was filed on December 29, 2015 and focused on methodology issues. Part 2 of the report was filed on February 26, 2016 and provided marginal cost estimates reflecting the Labrador-Island interconnection. The Rate Design Review Report which reviewed the Wholesale Rate of Newfoundland Power and the Island Industrial Customer rate was filed by Hydro on June 15, 2016.

standards. Under an open access regime, operating and maintenance costs associated with transmission facilities are recovered through a published transmission tariff. Reciprocity standards require that Hydro also pay the same published transmission tariff that is chargeable to outside third parties that want to flow energy on the Provincial transmission grid. However, OC2013-343 does not permit Hydro to recover costs of the Muskrat Falls Project from its customers until the near or full commissioning of the Muskrat Falls Project.[6]

In determining revenue requirements for the 2018 Test Year and the 2019 Test Year, Hydro is proposing to establish a deferral account which shall include any difference between: (i) the actual costs attributable to off-island power purchases including the cost of delivery; and (ii) the costs that would have been incurred if that same amount of energy had been supplied from the Holyrood Thermal Generating Station, based on the approved Test Years' unit cost of No. 6 fuel.

Hydro proposes that the costs incurred to use the Muskrat Falls Project transmission assets be recognized and paid for from the fuel savings.

Hydro also proposes that any fuel savings in excess of the cost of delivery be set aside for the benefit of Hydro's customers in reducing the customer rate impact from the recovery of Muskrat Falls Project costs. Hydro will file supplemental evidence in the fall of 2017 to provide more detail on the proposed deferral account which must align with the operation of the Rate Stabilization Plan.

Future customers will be required to provide recovery of the costs of the Muskrat Falls Project. Hydro considers it is reasonable that future customers should receive the benefit from any savings that can be achieved through the use of the Muskrat Falls Project transmission assets. Setting customer rates for 2018 and 2019 such that the potential net savings derived from the

[6] Section 3(b) of OC2013-343 requires that no costs (in respect to each of Muskrat Falls, the LTA or the LIL) shall be recovered in Hydro's rates until such time as the project is commissioned or nearing commissioning.

use of these transmission assets are deferred to mitigate the full Muskrat Falls Project costs is consistent with the principle of intergenerational equity.

Nalcor's June 23, 2017 project update stated that average island residential electricity rates would increase to 22.89 cents (¢) (plus HST) per kilowatt hour (kWh) in 2021. The present average rate for these customers is 11.7 ¢ per kWh (plus HST). Implementation of Hydro's GRA rate proposals including the Off-Island Purchases Deferral Account will increase the average Domestic customer rate from 11.7¢ per kWh (before HST) to approximately 13.3¢ per kWh (before HST) in 2019 (excluding the effects of RSP rate updates).

Alternatively, reflecting the forecast savings from pre-commissioning off-island purchases in the 2018 and 2019 Test Year revenue requirements is anticipated to keep rates flat or potentially reduce rates slightly. Currently, there is material uncertainty in the savings that will be achieved during the transition period. The actual savings that will accumulate in the proposed deferral account will vary depending on: (i) the availability date for the LIL and LTA; (ii) Holyrood fuel price; (iii) the availability of energy for import and the cost of that energy from other jurisdictions; and (iv) the cost of operating and maintaining the LIL and LTA.

Hydro considers its proposal to be consistent with the regulatory principle of rate stability and will assist in mitigating the anticipated Muskrat Falls Project rate shock.

The Board's approval of the proposed Off-Island Purchases Deferral Account will begin the transition to customer rates that will provide an opportunity to achieve reasonable recovery of Muskrat Falls Project costs. The current proposal is a critical step to set the foundation for the broader approach for rate mitigation to be successful.

5.3 2017 GRA Cost of Service Methodology Proposals

With the delay of the inclusion of Muskrat Falls Project costs in its cost of service, Hydro's 2017 GRA filing will materially reflect the existing approved cost of service methodology. However, there are certain cost of service issues not related to the completion of the Muskrat Falls Project that are required to be dealt with in the current GRA. These include:

(i) the CBPP Generation Credit Pilot Project;[7]
(ii) the assignment of the frequency converter to CBPP as a specifically assigned asset;
(iii) the methodology of allocating operating and maintenance costs to specifically assigned assets;
(iv) the demand and energy classification of wind purchases; and
(v) a further review of the Rural Deficit allocation methodology.

Mr. Bruce Chapman of Christensen Associates Energy Consulting (CA Energy) has reviewed the treatment of each of these matters and provided recommendations in a report provided as Exhibit 13. All other cost of service functionalizations, classifications, and allocations are consistent with past practice previously approved by the Board.

5.3.1 CBPP Generation Credit Pilot Project

Under the current pilot agreement initiated in 2009, CBPP's generation no longer needs to follow its load with the purpose of minimizing demand billed by Hydro. The generation credit approach allows CBPP to exceed its firm demand level without having to pay for interruptible energy. Other customers that exceed their firm demand pay for interruptible energy based on the utility's cost of thermal generation to provide non-firm energy.

In return for the generation credit, CBPP has been able to manage its hydraulic resources more efficiently from a system perspective and reduce the requirement for the use of Holyrood generation (i.e., reduce spilling). In addition, Hydro can call on CBPP to maximize its generation to provide additional capacity to the grid (to the extent that it is available at the time of the request) under this arrangement.

[7] The generation credit agreement between Hydro and CBPP was approved on a pilot basis by the Board in Order No. P.U. 4(2012).

Hydro's Cost of Service expert, CA Energy, reviewed the appropriateness of continuing the pilot project. The CA Energy review on this matter is provided in the Cost of Service evidence on pages 16 to 21 of Exhibit 13.

Once Hydro is connected to the North American grid, the marginal system energy cost can vary materially by hour and will no longer be based solely on Holyrood fuel. Hydro proposes that CBPP should not be able to exceed its firm demand requirements without paying the non-firm energy rate reflecting marginal costs of supplying non-firm load.

The benefits to all customers arising from the fuel cost savings that supported the pilot project implementation are not expected to continue upon commissioning of the Muskrat Falls Project. Therefore, Hydro is proposing to discontinue the generation credit agreement between Hydro and CBPP on December 31, 2018. However, Hydro would like to ensure that CBPP has the opportunity to manage its generation as efficiently as possible and, to that end, proposes to work with CBPP on initiating a new pilot project to start in 2019. That project will focus on developing pricing using Hydro's marginal costs reflecting interconnection with the North American grid.[8]

5.3.2 Assignment of the Frequency Converter to CBPP

Hydro is proposing no changes in its functionalization of specifically assigned assets. This includes the current assignment of the frequency converter as a specifically assigned asset to CBPP. Hydro is engaged in discussions to sell the frequency converter to CBPP. As of the date of filing, the parties have not reached an agreement to transfer the asset. If the asset sale proceeds, Hydro will discontinue the specifically assigned charge to CBPP. Hydro's application reflects the continuation of the costs of the frequency converter as being specifically assigned to CBPP.

[8] Hydro plans to file an application for a revised service agreement with CBPP once it determines whether a new pilot project will be implemented.

Please refer to pages 12 to 16 of Exhibit 13 for CA Energy's review of this matter.

5.3.3 Allocation of Operating and Maintenance Costs to Specifically Assigned Assets

Background

The Island Industrial Customer rate includes a customer-specific charge (specifically assigned charge) designed to recover the costs of transmission facilities specific to providing service to each customer.[9]

In the Amended 2013 GRA, Hydro proposed to increase specifically assigned charges from the 2007 Test Year approved amount of $0.7 million to $1.7 million. The most significant driver of the increase was operating and maintenance costs. Operating and maintenance cost allocations between assets functionalized as common or specifically assigned are calculated using the currently approved cost of service methodology which uses allocations based on the original asset cost. The addition of transmission assets to serve new industrial load in the past number of years has caused specifically assigned operating and maintenance costs to increase. Due to the inherent inverse relationship whereby older assets that cost less at the time of installation generally require more operating and maintenance than more expensive newer plant, Hydro's current method was contested by the Island Industrial Customer Group (CBPP and NARL) and Vale as being unjustly discriminatory as it created inequity for new industrial customers. Vale's expert, Mr. Dean, indicated that the ratio of the specifically assigned plant in service to total plant in service does not account for the time value of money.[10]

As part of the 2013 Amended GRA proceeding, Hydro conducted an analysis of an alternate operating and maintenance allocation method and presented a proposal to use an allocation

[9] Specifically assigned charges include operating and maintenance costs, return on debt and equity, and depreciation. For customers who make contributions in aid of construction (CIAC) for the assets, the specifically assigned charge is based on the estimated operating and maintenance cost for the specifically assigned asset.
[10] Expert's Report on Newfoundland and Labrador Hydro's 2013 General Rate Application, prepared by Mel Dean, April 25,2014; Section 2, page 10, line 7 through page 11, line 2.

based on determination of test-year transmission asset value via Handy-Whitman indexes.[11] The resulting specifically assigned operating and maintenance costs would have been reduced by over 50% from those originally proposed in the 2013 Amended GRA (i.e., from approximately $1 million per year to approximately $500,000 per year).

In Order No. P.U. 49(2016), the Board did not approve Hydro's proposed methodology change but indicated Hydro should address this issue more fully in its next GRA.

Methodology Review

As part of their Cost of Service methodology review conducted in early 2016, CA Energy reviewed the methodology for the allocation of operating and maintenance costs to specifically assigned assets. CA Energy found that the current method of allocation of operating and maintenance expenses is problematic since direct assignment on the basis of original asset costs appears to be poorly correlated with actual expense patterns over time.

CA Energy concluded that Hydro's recommended methodology presented at the 2013 GRA, to allocate operating and maintenance expenses based on determination of test-year transmission asset value via Handy-Whitman indexes, would be an improvement relative to the use of original assets costs. CA Energy also conducted a review of the methodologies employed in other jurisdictions for the allocation of operating and maintenance costs to assets that are specifically assigned to customers. The CA Energy research determined there is no generally accepted approach to allocating operating and maintenance costs to specifically assigned assets.

Please refer to pages 4 to 11 of Exhibit 13 for CA Energy's review of this matter.[12]

[11] See details of proposal in Hydro's response to Request for Information V-NLH-083 (Rev 1, June 23-2015).
[12] The CA Energy review is also provided in Appendix A, Section 5.3, beginning on page 61 of the *Cost of Service Methodology Review Report* filed with the Board on June 15, 2016.

The proposed change in approach to allocation of operating and maintenance costs between common assets and specifically assigned assets results in a decrease in the revenue requirement related to specifically assigned assets for both the Island Industrial Customers class and Newfoundland Power. This reduction in costs related to specifically assigned assets transfers these costs to common costs to be recovered from all customers on the Island Interconnected System. The effect of the proposed change is an increase in the Island Interconnected System revenue requirement related to common assets of approximately $380,000 in 2019 and an equal decrease in specifically assigned costs. The customer impact is an increase to Newfoundland Power of approximately $290,000 (0.1%) and a decrease to the Island Industrial class of approximately $290,000 (0.7%).[13]

Negotiation Process

Hydro consulted with the Island Industrial Customers prior to filing its GRA on the specific assignment methodology with respect to its proposal to use the constant dollar methodology for allocation of operating and maintenance costs to specifically assigned assets. The Island Industrial Customers indicated support for the proposed change in methodology; Hydro will also be initiating discussions with Newfoundland Power and the Consumer Advocate in an attempt to negotiate a settlement on this issue.

Hydro proposes to implement this revision to its cost of service methodology to become effective January 1, 2018 on an interim basis. The proposed methodology is reflected in the 2018 Test Year Cost of Service Study and the 2019 Test Year Cost of Service Study filed as Exhibits 14 and 15, respectively.

[13] The increased cost allocation to Newfoundland Power results from Newfoundland Power attracting the highest percentage of the revenue requirement functionalized as common (which is proposed to increase) and Island Industrial Customers comprising the highest percentage of revenue requirement functionalized as specifically assigned (which is proposed to decrease).

5.3.4 Classification of Purchases of Wind Generation

Hydro purchases wind generation from the wind farms at St. Lawrence (27 MW) and Fermeuse (27 MW), which began commercial operation in fall of 2008 and spring of 2009, respectively. In the 2013 Amended GRA, the Settlement Agreement provided for the purchase cost of wind generation to be classified as 100% energy-related.

Wind generation on the Island Interconnected System was initially cost-justified on the basis of reduced production at Holyrood. If the energy provided by wind generation had continued to be provided by Holyrood generation, then the energy costs would have been classified as 100% energy-related. From a system planning perspective, Hydro assumes that no wind generation will be available to supply system capacity requirements.

CA Energy has also reviewed the appropriate classification of wind purchases on the Island Interconnected System and supports the classification of purchases of wind generation as 100% energy-related. Please refer to pages 26 to 31 of Exhibit 13 for CA Energy's review of this matter.

Hydro is proposing that the purchased power costs related to wind continue to be classified as 100% energy related. This proposal is reflected in the 2018 Test Year Cost of Service Study and the 2019 Test Year Cost of Service Study.

5.3.5 Rural Deficit Allocation

In Order No. P.U. 49(2016), the Board approved Hydro's proposal to use the revenue requirement method to allocate the Rural Deficit between Newfoundland Power and the Labrador Interconnected System as of January 1, 2014. However, the Board stated that it expects that Hydro will address the Rural Deficit allocation methodology in its cost of service report to permit all parties to have further opportunity to provide input as part of the review of that report.[14]

CA Energy reviewed the methodology for allocation of the Rural Deficit in the *Cost of Service Methodology Review Report* filed with the Board on June 15, 2016. CA Energy also supported the use of the revenue requirement method to allocate the Rural Deficit.[15] Please refer to pages 21 to 26 of Exhibit 13 for CA Energy's review of this matter.

Hydro's allocation of revenue requirements for the 2018 Test Year and the 2019 Test Year reflects the allocation of the Rural Deficit using the revenue requirement method approved by the Board in Order No. P.U. 49(2016).

5.4 Recovery of Revenue Requirement

Table 5-1 provides a comparison of forecast billings from the existing rates that became effective July 1, 2017, to the forecast billings to provide recovery of the proposed revenue requirements for the 2018 and 2019 Test Years.

[14] See Order No. P.U. 49(2016), page 105, lines 20-22.

[15] The CA Energy review on Rural Deficit allocation is provided in Appendix A, Section 5.1, beginning on page 46 of the Cost of Service Methodology Review Report prepared by CA Energy and filed with the Board on June 15, 2016.

Table 5-1 Required Increase in Customer Billings to Recover Revenue Requirement[16]

Customer Class	2018 TY Increase Relative to July 1, 2017 Rates		2019 TY Increase Relative to July 1, 2017 Rates	
	$ million	%	$ million	%
Newfoundland Power	58.4	14.1	72.0	17.4
Island Industrial	3.8	9.6	4.7	11.8
Rural Labrador Interconnected	1.3	6.2	2.4	11.8
Labrador Industrial Transmission	0.9	19.7	2.1	44.9
Hydro Rural Government Diesel	0.3	12.8	0.5	22.0
Hydro Rural Other[17]	5.6	9.5	6.9	11.8
Total	70.3		88.6	

Table 5-1 indicates that approximately $70.3 million in additional revenue from customers is required to provide recovery of the 2018 Test Year revenue requirement in the absence of interim rates. An approximate additional $18.3 million is required through increased customer rates to provide recovery of the 2019 Test Year revenue requirement. Schedules 5-I and 5-II provide the supporting data for Table 5-1.

5.4.1 Requirement for Interim Rates

In Order Nos. P.U. 22(2017), P.U. 25(2017) and P.U. 26(2017), Hydro received approval of final rates from its 2013 Amended GRA to become effective July 1, 2017. The extended GRA process to finalize 2015 Test Year customer rates resulted in a delay in filing Hydro's current GRA until July 28, 2017. Hydro anticipates that new final rates resulting from the 2017 GRA process will not be in effect until the fourth quarter 2018 or the beginning of 2019. The implementation of new customer rates that recover 2019 Test Year revenue requirement from rates effective January 1, 2019, would result in a revenue deficiency of approximately $70.3 million for 2018 without interim relief.

[16] The change in billings provided in Table 5-1 reflects the elimination of the existing RSP fuel riders in 2019 but reflects no change in the RSP recovery adjustment rates.
[17] Includes Hydro Rural Isolated and Hydro Rural Interconnected, but excludes Hydro Rural Government Diesel. Hydro assumed these customers will receive the same rate increase as Newfoundland Power's retail customers, which is approximately 67.5% of Newfoundland Power's wholesale rate increase

The continuation of current rates, effective July 1, 2017, in 2018 would result in a net loss for Hydro of $10.7 million. Without interim rates, Hydro's 2018 Test Year return on equity would be -1.39% and return on rate base would be 3.84%, which is below the bottom of the approved range of rate of return on rate base of 6.41% established for the 2015 Test Year for rate setting.

During the course of the 2013 Amended GRA process, Hydro advised that several regulatory bodies across Canada have authorized utilities to implement interim rate increases. In Order No. P.U. 14(2016), the Board approved implementation of interim rate increases for Hydro, effective July 1, 2015. Hydro is proposing new interim customer rates to be implemented effective January 1, 2018, with the proposed increase providing recovery of approximately 70% of the increased revenue requirement for 2018.[18]

Table 5-2 provides the proposed 2018 interim rate increase for each class of customers and the required increase for each class proposed for January 1, 2019, to provide recovery of 2019 costs including recovery of the 2018 revenue deficiency over a 20-month period. The proposed rate increases provided in Table 5-2 do not include the projected rate increases for the annual update to the RSP adjustments.[19] Schedule 5-III provides the calculation of the customer impacts for Newfoundland Power and Island Industrial Customers reflecting approval of the proposed 2018 interim rates effective January 1, 2018. Schedule 5-IV provides the calculation of the customer impacts for Newfoundland Power and the Island Industrial Customers based on the proposed 2019 Test Year rates relative to the proposed 2018 interim rates.

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[18] Hydro's proposal is consistent with the Board's approval of an interim Utility Rate to apply to Newfoundland Power effective July 1, 2015. The impact of Order No. P.U.14(2014) provided approximately 70% recovery of the requested increase in revenue requirement for the 2015 Test Year.

[19] The effect of the rate mitigation implemented in 2017 to reduce the rate increases for Island Interconnected customers has resulted in RSP rate mitigation credits that will expire in July 2018. Depending on fuel price variability, the required rate increases from RSP updates may be material. Hydro will provide information to the Board and stakeholders for comment prior to filing an application to implement rate changes resulting from the RSP updates.

Table 5-2 Proposed Average Rate Increases (%)[20]

Customer Class	2018 Interim Increase Relative to July 1, 2017 Rates	2019 Increase Relative to Proposed January 1, 2018 Interim Rates
Newfoundland Power Wholesale	9.8	9.4
Newfoundland Power – Retail	6.6	6.4
Island Industrial	6.3	7.1
Rural Labrador Interconnected	4.4	8.2
Labrador Industrial Transmission	15.1	28.3[21]
Hydro Rural Government Diesel	8.9	13.8
Hydro Rural Other[22]	6.6	6.4

The Board's approval of interim rates effective July 1, 2015, during Hydro's last GRA was also effective in limiting the revenue deficiencies to be recovered from customers at the conclusion of the GRA. Hydro believes its proposed approach in the current GRA would also achieve this desired result. Sections 5.6 to 5.9 provide explanations for the proposed increases for each customer class. Exhibit 16 provides Hydro's proposed interim Schedule of Rates, Rules and Regulations.

5.5 Supply Cost Deferral Accounts

Hydro's supply cost forecast used in determining revenue requirements for the 2018 and 2019 Test Years reflects the continued use of No. 6 fuel at Holyrood as if the Island remained isolated from the North American grid. Any supply costs or savings resulting from off-island purchases for the Test Years will be set aside in the proposed Off-Island Purchases Deferral Account for future disposition to be determined by the Board in Hydro's next GRA.

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[20] The percentage increases were calculated assuming the RSP Current Plan riders under existing and proposed rates.

[21] The percentage increase in the Labrador Industrial Transmission rate does not provide the total customer billing impact as the percentage is calculated based on the projected change in transmission demand charges but does not include the non-regulated portion of the bill that recovers generation costs.

[22] Includes Hydro Rural Isolated and Hydro Rural Interconnected, but excludes Hydro Rural Government Diesel. Hydro assumed these customers will receive the same rate increase as Newfoundland Power's retail customers, which is approximately 67.5% of Newfoundland Power's wholesale rate increase

Hydro is not proposing any revisions to its supply cost deferral accounts in its 2017 GRA. Following the finalization of the proposed Off-Island Purchases Deferral Account, Hydro may be required to propose modifications to other supply cost deferral accounts to ensure cost alignment with no duplication among the deferral accounts.

5.6 Rate Design for Newfoundland Power

5.6.1 Background

In Board Order No. P.U. 44(2004), the Board approved the transition from an energy-only wholesale rate to a wholesale rate which included a demand charge and a blocking structure for energy charges. The Board also agreed that marginal costs should be considered in the future design of the wholesale rate.[23]

The mechanics for determining the Utility Rate for Newfoundland Power have included maintaining a second block price signal to reasonably reflect the price of Holyrood fuel, considering the demand rate in light of both marginal and embedded capacity costs and determining the first block rate to ensure the overall rate recovers the Newfoundland Power revenue requirement.

With the rate design review for Newfoundland Power and Island Industrial Customers scheduled to occur subsequent to the current GRA, Hydro is not proposing any change in the historical rate design approach. However, with the increased price of fuel to be reflected in the second block, Hydro is proposing a revision to the first block size to maintain a reasonable price for the first block. The details on the proposed rate are provided in the following sections.

[23] See page 13 of Order No. P.U. 44(2004).

5.6.2 Cost Review

Fuel Cost

The current tail block energy rate of 10.422¢ per kWh reflects the $64.41 per barrel fuel price divided by the 2015 Test Year Holyrood fuel conversion rate of 618 kWh per barrel.[24] The forecast No. 6 fuel cost is $86.41 per barrel ($Can) for the 2018 Test Year and $87.11 per barrel for the 2019 Test Year. Hydro is proposing the use of the 2019 Test Year to design its proposed final customer rates. Based on a Holyrood fuel conversion rate of 616 kWh per barrel,[25] the proposed tail block rate would equal 14.141¢ per kWh. The derivation of the second block price using this approach is consistent with the approved approach for determining the second block rate for Newfoundland Power in the 2003 GRA, 2006 GRA, and the 2013 Amended GRA.

The implementation of the proposed second block base rate of 14.141¢ per kWh in 2019 reflecting $87.11 per barrel would result in the elimination of the fuel rider in effect for Newfoundland Power currently reflecting the difference between $81.40 per barrel and the 2015 Test Year price of $64.41 per barrel.[26]

Demand Cost

The current demand charge of $4.75 per kW per month was negotiated in the 2013 Amended GRA giving consideration to marginal capacity costs and the increase in embedded demand costs.

The average embedded demand cost has increased from $9.71 per kW per month in the 2015 Test Year Cost of Service Study to $12.65 per kW per month in the 2019 Test Year Cost of

[24] The Board approved the use of a $64.41 per barrel fuel cost ($Can) for the 2015 Test Year based on a 2016 fuel price forecast which was filed with the Board on October 28, 2015.
[25] The 616 kWh per barrel reflects the proposed 2019 Test Year Holyrood No. 6 fuel conversion rate.
[26] This fuel price difference is reflected in the RSP fuel rider of 0.672¢ per kWh which applies to Newfoundland Power effective July 1, 2017, and was approved in Order No. P.U. 22(2017).

Service Study.[27] The system marginal costs for the purpose of rate design and cost allocation reflecting the Labrador-Island interconnection will be a component of the Cost of Service and Rate Design Methodology Review proposed to proceed in 2018 after the conclusion of 2017 GRA.[28]

Hydro believes a moderate increase in the demand charge is appropriate to continue to provide a demand management signal to Newfoundland Power and is proposing that the demand charge for Newfoundland Power in 2019 increase by approximately 10% to $5.25 per kW per month.

First Block Size

To maintain the current rate design approach with the higher price of fuel reflected in the second block, Hydro is proposing to increase the first block size from 250 GWh to 290 GWh per month. If Hydro maintained the 250 GWh block size, the price of the first block energy charge would be close to zero. The proposed approach reduces the amount of usage billed on the higher priced second block but still retains the fuel cost of Holyrood as the marginal price for all months of the year and maintains a reasonable first block energy charge.

5.6.3 Proposed 2019 Rate

Table 5-3 provides a summary of the rate structure for Newfoundland Power to recover the 2019 Test Year revenue requirement. The rate below is the proposed base rate to become effective January 1, 2019.

[27] The $12.46 per kW per month provides the unit cost excluding the Rural Deficit.

[28] Hydro filed two reports with the Board on marginal costs reflecting the Labrador-Island interconnection. Part 1 of the marginal report was filed on December 29, 2015 and focused on methodology issues. Part 2 of the marginal cost report was filed on February 26, 2016 and provided marginal cost estimates reflecting the Labrador-Island interconnection.

Table 5-3 Utility Base Rate Structure[29]

Component	Unit	Existing	2019 TY Proposed	Comments
Demand	$/kW/month	4.75	5.25	2015 TY rate was negotiated; proposed rate reflects 10% increase.
First Block	GWh/month	250	290	Block size designed to ensure some customer usage in second block in all months.
First Block	¢/kWh	2.226	3.821	Both rates equal the derived rate to achieve revenue requirement after the demand charge and second block rates were calculated.
Second Block	¢/kWh	10.422	14.141	Both rates reflect the forecast test year No. 6 fuel cost.

Hydro is not proposing an increase in the rate of 2.882 ¢ per kWh for firming up secondary energy purchased from CBPP and resold to Newfoundland Power as firm energy.

Hydro is also proposing an additional monthly charge of $902,506 to recover the forecast 2018 revenue deficiency from Newfoundland Power of $18,050,121 to be in effect for the period January 1, 2019 to August 31, 2020.[30]

The proposed Utility Rate schedule applicable to Newfoundland Power is included in the Schedule of Final Rates, Rules and Regulations provided in Exhibit 17. The RSP adjustment for the 2019 Test Year has been updated to set the fuel rider to zero in accordance with Section D of the RSP rules.

[29] The calculation of Newfoundland Power's rate is provided on Schedule 1.4 of the 2019 Cost of Service Study attached as Exhibit 15 to the Application.
[30] Hydro anticipates its customer base rates will again be required to increase September 1, 2020, to provide recovery of Muskrat Falls Project costs. This provides a 20-month period for the revenue recovery for the amortization of 2018 revenue deficiency.

5.6.4 Curtailable Credit

Hydro is proposing to continue to provide a curtailable credit in computing the billing demand for Newfoundland Power. The Curtailable Credit was implemented to ensure curtailable load is available and used efficiently to meet system load requirements.

Hydro believes the Curtailable Credit should be maintained until a review of the longer-term benefits of interruptible/curtailable load is completed giving consideration to the results of a marginal cost study and the rate design review reflecting the Labrador-Island interconnection. The requirement for the continuation of the curtailable credit beyond the full commissioning of the Muskrat Falls Project will be reviewed in the Cost of Service Methodology and Rate Design Review proposed for 2018.

5.6.5 Generation Credit

Hydro's proposed Utility Rate also includes an update to the Newfoundland Power Generation Credit from 119,329 kW to 118,054 kW based on the revised credit described in Section 3.5.2 of this Evidence. The slight reduction results from decreased thermal generation availability forecast through the 2018/19 operating seasons.

5.6.6 Proposed 2018 Interim Rates

As shown in Table 5-2, Hydro is proposing a 9.8% interim increase to Newfoundland Power to become effective January 1, 2018. This rate change would increase rates to end consumers by approximately 6.6%.[31] Hydro is proposing to vary the percentage increase to each rate component of the Utility Rate to prevent the additional revenues to be provided by interim rates from being transferred to the balance in the RSP.

[31] Includes Hydro Rural Isolated and Hydro Rural Interconnected, but excludes Hydro Rural Government Diesel. Hydro assumed these customers will receive the same rate increase as Newfoundland Power's retail customers, which is approximately 67.5% of Newfoundland Power's wholesale rate increase

During the 2013 Amended GRA process, the Board approved an interim Utility Rate effective July 1, 2015, with an equal percentage (8.0%) increase applied to each rate component for Newfoundland Power. However, the additional billings from the increase to the second block energy charge flowed through to the RSP Load Variation balance for the period while rates were interim (from July 1, 2015 to June 30, 2017).[32] As a result, Hydro did not treat these additional billings as revenue until the RSP was updated in 2017 to reflect the 2015 Test Year.

The operation of the RSP Load Variation component during the period of interim rates contributed to Hydro's revenue deficiencies in 2015 and 2016 prompting Hydro to request the Board to approve cost deferrals in 2015 and 2016 to avoid forecast financial losses for each year. To avoid this reoccurrence in 2018, Hydro is proposing that interim rate increases apply to rate components that do not impact the operation of the RSP. These include the demand charge and the first block energy charge.

Hydro is proposing to increase the wholesale demand charge from $4.75 per kW to $5.00 per kW (5.3%) on an interim basis. Hydro is also proposing to increase the first block energy charge to provide the remainder of the proposed interim rate increase. These rate changes have no impact on transfers to the RSP.

Table 5-4 provides a summary of the proposed interim rate structure for Newfoundland Power to become effective January 1, 2018.

[32] The operation of the RSP results in any change in billings resulting from an increase in the second block energy rate (without an offsetting fuel cost increase) being transferred to the RSP load variation component balance. Therefore, the approval of an interim increase on the second block energy rate in July 2015 did not provide any additional interim revenues to Hydro in 2015 and 2016 as the additional revenues were transferred to the balance sheet in the RSP Load Variation balance.

Table 5-4 Proposed Interim Utility Base Rate Structure

Component	Unit	Existing[33]	2018 Proposed
Demand	$/kW/month	4.75	5.00
First Block	GWh/month	250	250
First Block	¢/kWh	2.226	3.443
Second Block	¢/kWh	10.422	10.422

5.6.7 RSP Rural Rate Alteration

The Rural Rate Alteration (RRA) is a component of the RSP that transfers to Newfoundland Power the changes in Hydro Rural revenues that result from flowing through Newfoundland Power rate changes to Hydro Rural customers.[34]

The RSP rules require that actual billing data from Hydro Rural customers be used in the monthly RRA calculations. Hydro is proposing to modify the RSP rules to permit Test Year data to be used in computing the RRA amounts. Hydro's proposal will materially reduce the administrative effort in preparing the monthly RSP report[35] and will not have a material impact on RSP transfers.[36] The proposed revision in the RSP rules is provided in Schedule 5-V to this Evidence.

5.6.8 Hydro's Application

Hydro is requesting the Board's approval for the following changes in base rates to become effective January 1, 2018, on an interim basis:

- Demand Charge:

  $5.00 per kW of billing demand per month.

[33] Existing rates approved in Order P.U. 22(2017) effective July 1, 2017.

[34] Section B 1.3 of the Rate Stabilization Plan rules defines the method by which Hydro calculates the Rural Rate Alteration.

[35] Hydro must calculate the RRA rate variance on more than 27,000 customer bills on a monthly basis. The compiling of this data and resulting calculation is time consuming and tedious. For example, in order to ensure compliance with the 'Actual Units' requirement, there are instances where Hydro must calculate the RRA on an individual customer basis.

[36] Computing the 2016 RRA transfer using Test Year units instead of actual units resulted in a difference of 0.3%, which represents a variance of less than $25,000 on a 2016 RRA transfer of over $8.0 million.

- Energy Charge:
  First 250,000,000 kilowatt-hours @ 3.443 ¢ per kWh
- Revised RSP rules to permit Test Year billing data to be used in computing the RRA amounts.

The proposed Schedule of Rates, Rules and Regulations to become effective on an interim basis effective January 1, 2018, is provided in Exhibit 16.

Hydro is requesting the Board's approval for the following to be effective on a final basis January 1, 2019:

- Demand Charge:
  $5.25 per kW of billing demand per month.
- Energy Charge:
  First 290,000,000 kilowatt-hours @ 3.821 ¢ per kWh
  All excess kilowatt-hours @ 14.141 ¢ per kWh
- Firming-up Charge: @ 2.882 ¢ per kWh
- Monthly revenue deficiency charge of $902,506 for the period January 1, 2019 to August 31, 2020.
- Removal of the fuel rider of 0.672¢ per kWh.
- Revised RSP rules to permit Test Year billing data to be used in computing the RRA amounts.

The proposed Schedule of Rates, Rules and Regulations to become effective January 1, 2019 on a final basis is provided in Exhibit 17.

5.7 Rates for Island Industrial Customers

5.7.1 General

With the rate design review scheduled subsequent to the current GRA, Hydro is not proposing any change in the past rate design approach for Island Industrial Customers.

5.7.2 Firm Rates

Rates charged to Island Industrial Customers for firm power and energy are designed based upon the average embedded costs from the 2019 Test Year Cost of Service. Hydro has calculated a firm service rate comprised of a demand charge of $11.12 per kW of billing demand per month and an energy charge of 4.792 ¢ per kWh plus specifically assigned charges. Hydro is also proposing rate riders for both demand and energy to apply to provide recovery of the 2018 revenue deficiency over the period January 1, 2019 to August 31, 2020.[37]

Table 5-5 provides a comparison of the existing and proposed final demand and energy base rates for Island Industrial Customers based on the 2019 Test Year.

Table 5-5 Industrial Customer Demand and Energy Charges

	Existing	Proposed
Demand charge ($/kW/month)	7.99	11.12
Energy charge (¢ per kWh)	3.971	4.792

Specifically assigned charges recover costs incurred for assets that are in service solely for each Island Industrial Customer.[38] These costs include operating and maintenance costs, depreciation, and return on the specifically assigned assets.[39] Table 5-6 provides a comparison of the existing and proposed final specifically assigned charges by customer.

Table 5-6 Industrial Customer Specifically Assigned Charges ($)

Customer	Approved	Proposed
CBPP	870,898	861,911
NARL	89,293	193,496

[37] This proposal assumes the Board approves the proposed changes in specifically assigned charges on an interim basis.
[38] For the Newfoundland Power rate design, there is no specifically assigned charge as these costs are blended in the second block energy charge which is priced to reflect the marginal cost of Holyrood No. 6 fuel.
[39] When a customer has paid a contribution in aid of construction for the specifically assigned assets, the costs reflected in the specifically assigned charge only recover the allocation of operating and maintenance costs for the specifically assigned assets.

Teck	199,399	51,566
Vale	480,243	170,233
Praxair[40]	-	-
Total	**1,639,833**	**1,277,206**

The overall decrease in the proposed specifically assigned charges results from the proposed methodology change presented in Section 5.3.3. However, as shown in Table 5-6, the proposed revised methodology does result in an increase in the specifically assigned charges to NARL.

5.7.3 Non-firm Rates

The Island Industrial Customer contracts currently include a provision for interruptible demand.[41] The standard definition is as follows:[42]

> *"Interruptible Demand" means, that part of a Customer's Demand which exceeds its Power on Order, which may be interrupted, in whole or in part, at the discretion of Hydro and which is supplied to the Customer in accordance with Clause …"*

The 2019 Test Year Cost of Service Study does not include interruptible demand in determining the peak demand for the Island Industrial Customer class for cost allocation. The interruptible demand reflects the non-firm load requirement in the standard Island Industrial Customer contracts. When customers are using interruptible demand, they are generally required to pay

[40] There are no specifically assigned charges for Praxair as there are no transmission or terminal station assets solely for the provision of service to this customer.

[41] Provided the Amount of Power on Order is equal to or greater than 20,000 kW, the amount of Interruptible Demand and Energy available shall be the greater of 10% of the Amount of Power on Order and 5,000 kW. If the Amount of Power on Order is less than 20,000 kW, the Amount of Interruptible Demand and Energy available shall be 25% of the Amount of Power on Order.

[42] The definition is slightly different for Corner Brook Pulp and Paper since there is "Generation Outage Demand." The provision states: "Interruptible Demand" means, that part of a Customer's Demand, other than its Generation Outage Demand, which exceeds its Power on Order, which may be interrupted, in whole or in part, at the discretion of Hydro, and which is supplied to the Customer in accordance with Clause 4.01 of the Service Agreement.

for their additional energy requirements based upon the cost of fuel for the thermal generation source providing energy.[43]

For non-firm service, Hydro is proposing to retain the previously approved calculation for the energy charge with an update to the loss factors. The loss factor has been updated to the five-year average Island Interconnected System losses, from 3.47% to 3.34%.

Hydro has also updated its wheeling rate from 0.423¢ per kWh to 0.895¢ per kWh for Island Industrial Customers to reflect 2019 Test Year costs. There are no customers currently accessing the wheeling rate. However, Hydro is proposing to maintain the rate in the event that it may be required until it is replaced with the implementation of an open access transmission tariff.

5.7.4 Proposed 2018 Interim Rates

As shown in Table 5-2, Hydro is proposing a 6.3% interim increase to Island Industrial Customers to become effective January 1, 2018. Hydro is proposing to vary the increase in demand and energy charges to provide equal percentage cost recovery for each component. However, Hydro is proposing the increase in the energy charge be maintained as an interim rate rider separate from the base energy rate. This approach will avoid the additional billings provided by interim rates from flowing into the RSP Load Variation balance. The rationale for this approach is explained in Section 5.6.6.

Hydro is proposing to implement the proposed specifically assigned charges on an interim basis effective January 1, 2018. In this manner, the revenue deficiency or excess revenues related to specifically assigned charges will not be reflected in the class revenue deficiency.[44] Interim implementation of the specifically assigned charges derived from the 2018 Test Year Cost of

[43] Because CBPP runs its generation to maximum capacity at the request of Hydro, CBPP is currently permitted to exceed its firm demand requirements without paying the non-firm energy price as long as thermal generation is not being operated to meet system energy requirements. Please refer to Section 5.3.1.

[44] In the 2013 GRA, there was a disagreement among Island Industrial Customers on the recovery of revenue deficiency related to specifically assigned charges. The disagreement related to whether revenue deficiency related to specifically assigned charges should be recovered on a class basis versus an individual customer basis.

Service Study will allow the class revenue deficiency for 2019 to be recovered [] through demand and energy rate riders.[45]

Hydro is also proposing to increase the demand charge from $7.99 per kW to $9.93 per kW and increase the energy charge from 3.971¢ per kWh to 4.071¢ per kWh to obtain the proposed 6.3% overall class average rate increase on an interim basis. The proposed interim rates recover 70% of the forecast increase in both demand and energy costs from Island Industrial Customers in 2018.

5.7.5 Hydro's Application

Interim Rates

Hydro is requesting the Board's approval for an increase in the demand charge from $7.99 per kW to $9.93 per kW on an interim basis effective January 1, 2018.

Hydro is requesting the Board's approval for the approval of an interim energy rate rider of 0.100¢ per kWh on an interim basis effective January 1, 2018.

Hydro is requesting the Board approve the following specifically assigned charges, as shown below, on an interim basis effective January 1, 2018.

	Annual Amount
Corner Brook Pulp and Paper Limited	$732,673
North Atlantic Refining Limited	$183,050
Teck Resources Limited	$51,173
Vale Newfoundland and Labrador Inc.	$165,774

[45] If the Board determines that the current methodology of allocation of operating and maintenance expenses to specifically assigned charge methodology should remain in effect, Hydro will propose that any revenue deficiency from specifically assigned charges be recovered on an individual customer basis.

The proposed Schedule of Rates, Rules and Regulations to become effective on an interim basis effective January 1, 2018, is provided in Exhibit 16.

Final Rates

Hydro is requesting the Board's approval for the following effective January 1, 2019:

- Billing Demand Charge per month: $11.12 per kW
- Firm Energy Charge: Base Rate @ 4.792¢ per kWh
- Specifically Assigned Charges as follows:

	Annual Amount
Corner Brook Pulp and Paper Limited	$861,911
North Atlantic Refining Limited	$193,496
Teck Resources Limited	$51,566
Vale Newfoundland and Labrador Inc.	$170,233

- Average system losses of 3.34% to be used in the calculation of the energy charge to Industrial Customers for non-firm service;
- The updated Island Industrial wheeling rate of 0.895¢ per kWh;
- The discontinuation of the generation credit provided as a result of the CBPP pilot project effective December 31, 2018;
- The approval of a demand rate rider to recover the demand-related revenue deficiency for 2018 Test Year of $0.50 per kW for the period January 1, 2019 to August 31, 2020; and
- The approval of an energy rate rider to recover the energy-related revenue deficiency for 2018 Test Year of 0.025¢ per kWh for the period January 1, 2019 to August 31, 2020.

The proposed Schedule of Rates, Rules and Regulations to become effective January 1, 2019 on a final basis is provided in Exhibit 17.

5.8 Rates for Rural Customers

5.8.1 General

For rate-setting purposes, there are three distinct groups of Rural Customers:

- Island Interconnected and L'Anse au Loup Systems;
- Island and Labrador Isolated Systems; and
- Labrador Interconnected System.

Rates proposed in this Application for Rural Customers are based upon the policies for Hydro Rural rates as approved in Order No. P.U. 14(2007) and by Government direction. Hydro is proposing to apply the same increase to all classes of service on the Labrador Interconnected System with the exception of Street and Area Lighting. The reason for this proposed approach is provided in Section 5.8.4.

Excluding Government departments in isolated diesel areas, rates for Rural Customers on the Island Interconnected, L'Anse au Loup, and Isolated Systems, including preferential rate customers, will continue to be based on Newfoundland Power rates.

Rates for Government departments in isolated diesel areas will continue to be based on 100% cost recovery. Rates for Labrador Interconnected Customers are also proposed to recover fully allocated costs.

Hydro is proposing the following changes in its Rules and Regulations to become effective on an interim basis effective January 1, 2018:

- Section 9 (b) - revised to be consistent with Newfoundland Power and remove the requirement of payment in advance for temporary service charges;
- Section 9 (c) - revised to be consistent with Newfoundland Power and remove the requirement of payment in advance for special facilities; and

- Section 16 - revised to include the approved rate setting approach to apply to the Burgeo School and Library.[46]

Hydro is also proposing a change in its rate schedules for its isolated systems and the Labrador Interconnected System to provide the same 1.5% early payment discount as is available to Hydro Rural customers on the Island Interconnected System. This approach will also provide the same early payment discount as provided to customers of Newfoundland Power.

A comparison of the existing and proposed regulations is provided in Schedule 5-VI to this Evidence. The proposed revised regulations are also provided in the proposed Schedule of Rates, Rules and Regulations to become effective on an interim basis effective January 1, 2018, provided in Exhibit 16, and the proposed Schedule of Rates, Rules and Regulations to become effective on a final basis provided in Exhibit 17.

5.8.2 Island Interconnected and L'Anse au Loup Systems

Hydro's rates for Rural Customers on the Island Interconnected and L'Anse au Loup Systems are the same as the rates charged to Newfoundland Power customers. It is estimated that Hydro's proposed rates for Newfoundland Power will see a flow-through increase for these customers of approximately 6.6% on an interim basis effective January 1, 2018, compared to the existing rates that became effective on July 1, 2017, and an additional 6.4% effective January 1, 2019. Hydro is proposing to increase the rate to the Burgeo School and Library by the average increase to be applied to Newfoundland Power's customers.[47]

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[46] In its 2007 GRA, Hydro had proposed that Rate 1.3 be closed. However, in its written submission dated February 9, 2007, Hydro indicated to the Board that it was withdrawing its proposal to close this rate class. In Board Order No. P.U. 14(2007), the Board approved a 15.10% rate increase for Rate 1.3 as a result of Hydro's 2007 GRA. The rate sheet for Rate 1.3 was reinstated reflecting this increase; however, Section 16(a)(iii) pertaining to automatic rate changes was erroneously omitted. As such, Hydro proposes to include the automatic adjustment language in its Schedule of Rates, Rules and Regulations, effective January 1, 2018. Further, Hydro is proposing to increase the Burgeo School and Library rate on a prospective basis to match the average rate increase for Newfoundland Power.

[47] In Order No. P.U. 20(2004) the Board approved for inclusion in the policies for automatic rate changes that: "Rates for the Burgeo school and library will increase or decrease by the average rate of change granted

5.8.3 Isolated Systems

For rate-setting purposes, there are three customer groups in the isolated systems:

(i) Rural Domestic Customers, excluding Government Departments;
(ii) Rural General Service Customers, excluding Government Departments; and
(iii) Government Departments.

Hydro's rates for Rural Domestic Customers, excluding Government departments, are the same as Newfoundland Power's rates for the basic customer charge and first block consumption (lifeline consumption),[48] but non-lifeline consumption is adjusted by the average rate of change granted to Newfoundland Power.

Rates for Rural General Service Customers on the isolated systems are normally adjusted by the average rate of change approved for the customers of Newfoundland Power.

Government rate classes in isolated systems pay cost-based rates and Hydro proposes that the 2019 Test Year cost recovery level for Government departments remains at 100%. Hydro is proposing an interim increase of 8.9% in Government rates to become effective January 1, 2018, and a 13.8% increase to be implemented on a final basis effective January 1, 2019. Schedule 5-VII (page 1) provides a comparison of existing rates effective July 1, 2017, to the proposed interim rates to become effective January 1, 2018, and the proposed final rates to become effective January 1, 2019.

The 2019 revenue to cost ratio for customers on the Island and Labrador Isolated Systems, excluding L'Anse au Loup, is projected to be 0.14 and 0.22, respectively, for a combined revenue to cost ratio of 0.20.

Newfoundland Power from time to time, excluding Newfoundland Power's changes for the July 1st Municipal Tax and Rate Stabilization adjustments and for any Fuel Rider adjustments."

[48] The lifeline block is designed to provide Domestic Customers with access to electricity at non-discriminatory prices for essential services. Essential services include most electrical appliances and hot water heating, but not electric heat.

5.8.4 Labrador Interconnected

Hydro is proposing an average interim rate increase of 4.4% to become effective January 1, 2018, and an additional 8.2% to become effective January 1, 2019, for all Hydro Rural classes on the Labrador Interconnected System with the exception of Street and Area Lighting.

The 2019 Test Year Cost of Service Study indicates Hydro's existing Street and Area Lighting rates are providing full cost recovery. Therefore, Hydro is proposing no increase in Street and Area Lighting rates on the Labrador Interconnected system for 2018 or 2019.

Hydro has undertaken an Automated Meter Reading (AMR) project for the Labrador Interconnected System. Hydro plans to use the data collected from the AMR meters to update its class load research information for use in its next GRA. This data will allow Hydro to evaluate the reasonableness of the revenue to cost ratios by class prior to its next GRA. Hydro has reliable estimates of class load for the Street and Area Lighting class as a result of knowing the connected load of each lighting type and the timing of system peaks and class peak.

The proposed rates to become effective on an interim basis effective January 1, 2018, are provided in Exhibit 16. The proposed rates to become effective on a final basis effective January 1, 2019, are provided in Exhibit 17.

Schedule 5-VII (page 2) provides a comparison of the existing and proposed rates for rural customers on the Labrador Interconnected System.

5.8.5 Hydro's Application

Hydro is requesting that the Board approve the following proposals:

- amended Section 9(b), 9(c), and Section 16 of the rules and regulations for service to all Hydro Rural Customers to be approved on an interim basis effective January 1, 2018, and to be approved on a final basis effective January 1, 2019;

- rates for Isolated Rural Customers - Government as set out in the Schedule of Rates, Rules and Regulations provided in Exhibit 16 to this Application to be effective on an interim basis January 1, 2018;
- rates for Isolated Rural Customers - Government as set out in the Schedule of Rates, Rules and Regulations provided in Exhibit 17 to this Application to be effective on a final basis January 1, 2019;
- rates for Labrador Interconnected Rural Customers as set out in the Schedule of Rates, Rules and Regulations provided in Exhibit 16 to this Application to be effective on an interim basis effective January 1, 2018; and
- rates for Labrador Interconnected Rural Customers as set out in the Schedule of Rates, Rules and Regulations provided in Exhibit 17 to this Application to be effective on a final basis January 1, 2019.

5.9 Labrador Industrial Rates

5.9.1 Background

In December 2012, the Provincial Government introduced a series of legislative amendments to establish a new electricity rate policy for Industrial Customers on the Labrador Interconnected System. While the Board does not have jurisdiction over the establishment of the generation rate for Labrador Industrial Customers, legislation does provide that the transmission component of Labrador Industrial rates be fully regulated by the Board, beginning in 2015.[49]

Hydro has two mining facilities served on the Labrador Industrial rates, IOC and Wabush Mines. IOC's Power on Order is forecast to be 245.0 MW for 2018. Wabush Mines is currently not operational but still using a minimal amount of demand.[50] Wabush Mines has been recently purchased and may reopen in late 2018. The IOC demand requirements currently require almost 60% of the peak demand on the Labrador Interconnected System.

[49] Section 5.8(2) of the *Electrical Power Control Act,1994* states: "The *Public Utilities Act* shall not apply to the setting of electricity rates for Industrial Customers in Labrador other than the transmission components of those rates, which shall be regulated under subsection (1)."

[50] The forecast demand requirement for Wabush Mines in the 2018 Test Year is 0.3 MW.

Labrador West transmission is nearing its capacity limitations.[51] The cost of providing new transmission to meet load growth on the Labrador Transmission System is high and can materially impact future customer rates.

The current Labrador Industrial rates include an inclining block rate that applies to recover generation energy costs, a minimal demand charge of 0.42¢ per kW which applies to recover an allocation of regulated generation demand costs, and a regulated transmission demand charge of $1.19 per kW.[52] In Order No. P.U. 49(2016), the Board approved the transmission demand rate to be available to existing customers only.

5.9.2 Proposed Industrial Transmission Rate Design

Hydro is proposing to continue to use the same methodology to determine the costs to be recovered from the Labrador Industrial Transmission Customers.[53] The average embedded cost for transmission demand allocated to Labrador industrial Customers has increased from the $1.19 per kW approved for the 2015 Test Year to $1.44 per kW for the 2018 Test Year and $1.86 per kW for the 2019 Test Year. The increase results from the additional transmission investment on the Labrador Interconnected System reflected in the 2018 and 2019 Test Years compared to 2015 Test Year.[54] The derivation of the embedded transmission demand costs is provided in Schedule 5-VIII.

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[51] In OC2014-034, Hydro was directed to construct a new 230 kV transmission line between Churchill Falls and Labrador West; the budget for this line was approximately $330 million. The project was suspended in September 2014.

[52] The Board approved a Labrador Industrial Transmission Rate of $1.19 per kW per month effective July 1, 2017 in Order No. P.U. 22(2017). The Board also approved the 2015 Test Year Cost of Service Study used to determine the $0.42 per kW non-regulated generation demand rate to provide generation demand cost recovery.

[53] Hydro has isolated the Labrador Industrial transmission revenue requirement in accordance with the approved Cost of Service functionalization. The transmission costs were classified as 100% demand-related, consistent with the approved classification methodology. The transmission demand-related costs were then allocated between Labrador Industrial Customers and Rural Customers based on the approved single coincident peak allocation method.

[54] While the percentage increases in the transmission demand charge are large, the percentage change does not reflect the overall customer billing impact as the generation energy costs incurred by the customer comprise the largest component of the billing charges to Labrador Industrial customers. Based on the forecast energy requirements of the Labrador Industrial Customers in the 2019 Test Year Cost of Service Study, the proposed

Even with the increased embedded cost, the cost of transmission on a per kW basis on the Labrador Interconnected System is low. The comparable transmission cost on the Island interconnected System is near $4 per kW per month. The major contributing factor to the lower embedded cost of transmission in Labrador is funding; the original transmission line from Churchill Falls to Labrador West was funded by Labrador's mining companies. The capital cost of new transmission line facilities servicing Labrador West from Churchill Falls is projected to be in the range of $5 to $6 per kW. The higher cost of new transmission investment demonstrates that using the embedded transmission cost alone to derive the demand rate does not provide an adequate signal to promote efficient use of the transmission capacity.

The Labrador Industrial class peaks in the winter period, which is consistent with the system peak on the Labrador Interconnected System. Growth in system peak will accelerate the requirement for additional transmission on the Labrador Interconnected System. Hydro considers it appropriate to provide an improved price signal to promote effective demand management by the Labrador Industrial Customer class. Accordingly, Hydro is proposing a change to the Labrador Industrial rate design to promote effective use of resources through efficient demand management. Hydro is proposing an inclining block rate structure for the Labrador Industrial Transmission demand charge. Hydro is proposing this rate change be implemented on an interim basis effective January 1, 2018.

The proposed modification to the rate design does not change the total Test Year cost to be recovered from Labrador Industrial Transmission Customers. However, the proposed rate design provides a stronger financial incentive for the Labrador Industrial Customers to reduce their winter peak demands. Reduced peak demand from this customer class can contribute to reduced costs for all customers on the Labrador Interconnected System.

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allocated transmission demand costs of approximately $5.5 million equates to an average unit cost of 0.315¢ per kWh.

The proposed higher priced second block will apply when the customer's load is in excess of 90% of its annual Power on Order. The proposed rate design to become effective January 1, 2018 on an interim basis is as follows:

First Block (90% of Annual Power on Order)	@$1.34 per kW per month
Excess	@$2.83 per kW per month[55]

The proposed interim rate provides recovery of 70% of the additional transmission revenue requirement for the 2018 Test Year from the Labrador Industrial Transmission class. The proposed 2018 interim rate also includes a revised billing demand definition, and is provided in Exhibit 16. The revised billing demand provides for the customers' monthly demand costs to increase or decrease when the amount of demand required is in excess of 90% of the customer's annual Power on Order.

In concert with Hydro's proposal to implement a revised rate design for Labrador Industrial Customers, Hydro will also work with customers to identify opportunities to better manage their demand requirements.

For 2019 final rates, the first block demand charge is proposed to increase to $1.86 per kW and the second block rate is proposed to increase to $3.95 per kW.[56] A comparison of existing and proposed rates for the Labrador Industrial Transmission class is provided in Schedule 5 VII (page 3).

5.9.3 Generation Costs for Labrador Industrial Customers

The generation demand costs allocated to Labrador Industrial Customers will continue to be recorded by Hydro as a cost recovery and included in Other Revenues.

[55] The proposed excess demand rate is designed to recover 12% of the transmission revenue requirement from the Labrador Industrial Customer class.
[56] The proposed final rate to become effective January 1, 2019 includes a recovery of the 2018 revenue deficiency.

5.9.4 Hydro's Application

Hydro is requesting the Board to approve the following proposals:

- The proposed regulated transmission demand rate for Labrador Industrial Customers provided in Exhibit 16 to be implemented on an interim basis effective January 1, 2018; and
- The proposed regulated transmission demand rate for Labrador Industrial Customers provided in Exhibit 17 for Labrador Industrial Customers to be implemented on a final basis effective January 1, 2019.

5.10 Summary

Table 5-7 provides a comparison of customer billings between existing rates, effective July 1, 2017 and the interim rates, proposed to become effective January 1, 2018.

Table 5-7 Comparison of 2018 Test Year Billings at Existing and Proposed Interim Rates

	July 1/17 Existing Rates	Jan 1/18 Interim Rates	$ Change	% Change
Newfoundland Power				
Firm	433.2	473.5	40.3	
RSP - Current Plan	(60.7)	(60.7)	-	
RSP - Fuel Rider	39.1	39.1	-	
CDM Recovery Rider	1.1	1.1	-	
Total Firm NP	**412.7**	**453.0**	**40.3**	**9.8%**
Island Industrial				
Island Industrial Firm	39.8	42.3	2.5	6.3%
Island Industrial Non-Firm	-	-	-	
RSP - Current Plan	(5.0)	(5.0)	-	
RSP - Fuel Rider	4.5	4.5	-	
CDM Recovery Rider	0.1	0.1	-	
Island Industrial Total	**39.4**	**41.9**	**2.5**	**6.3%**
Labrador Industrial				
Transmission	3.5	4.0	0.5	14.9%
Generation Cost Recovery	1.2	1.4	0.2	15.2%
Labrador Industrial Total	**4.7**	**5.5**	**0.7**	**15.1%**
Canadian Forces Base Goose Bay	-	-	-	
Rural Island Interconnected	48.4	51.6	3.2	6.6%
Rural Isolated Systems	7.9	8.4	0.5	6.6%
Rural Isolated Government	2.1	2.3	0.2	8.9%
L'Anse au Loup	2.9	3.1	0.2	6.6%
Rural Labrador Interconnected				
Domestic	11.0	11.5	0.5	4.5%
GS 2.1 0 - 10 kW	0.4	0.4	0.0	4.5%
GS 2.2 10 - 100 kW	2.2	2.3	0.1	4.5%
GS 2.3 110 - 1000 kVA	3.4	3.6	0.2	4.5%
GS 2.4 Over 1000 kVA	2.6	2.7	0.1	4.6%
Street & Area Lighting	0.4	0.4	-	0.0%
Rural Labrador Interconnected Total	**20.0**	**20.9**	**0.9**	**4.4%**
All Rural Systems Total	**81.2**	**86.2**	**5.0**	**6.1%**
Grand Total	**538.1**	**586.6**	**48.5**	**9.0%**

Table 5-8 provides a comparison of customer billings between 2018 interim rates, proposed to become effective January 1, 2018, and 2019 final rates, proposed to become effective January 1, 2019.

Table 5-8 Comparison of 2019 Test Year Billings at 2018 Interim and 2019 Proposed Rates

	Jan 1/18 Interim Rates	Jan 1/19 Proposed Rates	$ Change	% Change
Newfoundland Power				
Firm	474.3	556.2	81.9	
RSP - Current Plan	(60.8)	(60.8)	-	
RSP - Fuel Rider	39.2	-	(39.2)	
CDM Recovery Rider	1.1	1.1	-	
Total Firm NP	**453.8**	**496.5**	**42.7**	**9.4%**
Island Industrial				
Island Industrial Firm	42.9	50.5	7.6	
Island Industrial Non-Firm	-	-	-	
RSP - Current Plan	(5.1)	(5.1)	-	
RSP - Fuel Rider	4.6	-	(4.6)	
CDM Recovery Rider	0.1	0.1	-	
Island Industrial Total	**42.5**	**45.5**	**3.0**	**7.1%**
Labrador Industrial				
Transmission	4.0	5.6	1.6	
Generation Cost Recovery	1.4	1.4	(0.0)	
Labrador Industrial Total	**5.5**	**7.0**	**1.5**	**28.3%**
Canadian Forces Base Goose Bay	-	-	-	
Rural Island Interconnected	51.0	54.3	3.3	6.4%
Rural Isolated Systems	8.5	9.0	0.5	6.4%
Rural Isolated Government	2.3	2.6	0.3	13.8%
L'Anse au Loup	3.1	3.3	0.2	6.4%
Rural Labrador Interconnected				
Domestic	11.5	12.5	1.0	8.4%
GS 2.1 0 - 10 kW	0.4	0.5	0.0	8.4%
GS 2.2 10 - 100 kW	2.3	2.5	0.2	8.4%
GS 2.3 110 - 1000 kVA	3.6	3.9	0.3	8.3%
GS 2.4 Over 1000 kVA	2.6	2.9	0.2	8.4%
Street & Area Lighting	0.4	0.4	0.0	0.0%
Rural Labrador Interconnected Total	20.9	22.6	1.7	8.2%
All Rural Systems Total	**85.7**	**91.8**	**6.0**	**7.0%**
Grand Total	**587.5**	**640.8**	**53.3**	**9.1%**

Chapter 5 – Schedule I

2018 Required Increase Relative to Existing Rates

Newfoundland and Labrador Hydro
2018 Required Increase Relative to Existing Rates[1]
Newfoundland Power

	2018 Test Year Billing Units	Unit	Existing Rate[2]	Existing Billings $	Existing Rate[2]	Revenue Requirement 2018 Cost of Service	$ Change	Percent Change Utility	Percent Change Consumer
Demand (kWs)	15,164,832	$/kW/mo	4.75	72,032,952					
Energy (MWhs)	3,000,000	¢/kWh	2.226	66,780,000					
Energy (MWhs)	2,824,500	¢/kWh	10.422	294,369,390					
Total Base Rate				433,182,342		530,674,320			
RSP Recovery Adjustment-Normal	5,824,500	¢/kWh	(0.132)	(7,688,340)	(0.132)	(7,688,340)			
RSP Mitigation impact	5,824,500	¢/kWh	(0.911)	(53,061,195)	(0.911)	(53,061,195)			
RSP Fuel Rider	5,824,500	¢/kWh	0.672	39,140,640	-	-			
CDM Recovery Adjustment	5,824,500	¢/kWh	0.019	1,106,655	0.019	1,106,655			
Total				**412,680,102**		**471,031,440**	**58,351,338**	**14.1%**	**9.5%**

[1] Hydro has assumed continuation of the existing RSP and CDM recovery riders that became effective July 1, 2017.

[2] Based on rates effective July 1, 2017.

Newfoundland and Labrador Hydro
2018 Required Increase Relative to Existing Rates[1]
Island Industrial Customers

	2018 Test Year Billing Units	Unit	Existing Rate[2]	Existing Billings $	Existing Rate[2]	Revenue Requirement 2018 Cost of Service	$ Change	Percent Change
Demand (kWs)	1,170,000	$/kW/mo	7.99	9,348,300				
Energy - Firm (MWhs)	726,000	¢/kWh	3.971	28,829,460				
Spec. Assigned		$	1,639,833	1,639,833				
Total Base Rate				39,817,593		48,126,347		
RSP: Current Plan	726,000	¢/kWh	(0.373)	(2,707,980)	(0.373)	(2,707,980)		
RSP: Current Plan Mitigation	726,000	¢/kWh	(0.313)	(2,272,380)	(0.313)	(2,272,380)		
RSP: Fuel Rider	726,000	¢/kWh	0.625	4,537,500	-	-		
CDM Recovery Adjustment	726,000	¢/kWh	0.009	65,340	0.009	65,340		
Total				**39,440,073**		**43,211,327**	**3,771,254**	**9.6%**

[1] Hydro has assumed continuation of the existing RSP and CDM recovery riders that became effective July 1, 2017.

[2] Based on rates effective July 1, 2017.

Newfoundland and Labrador Hydro
2018 Required Increase Relative to Existing Rates
Remaining Classes

	2018 Test Year Billing Units	Unit	Existing Average Unit Cost[1]	Existing Billings $	Proposed Average Unit Cost[2]	Revenue Requirement 2018 Cost of Service	$ Change	Percent Change
Rural Labrador Interconnected	656,143,630	$/kWh	0.031	20,166,629	0.033	21,426,998	1,260,369	**6.2%**
Hydro Rural Government	2,397,490	$/kWh	0.866	2,075,526	0.976	2,340,246	264,720	**12.8%**
Hydro Rural Other	491,216,300	$/kWh	0.120	59,169,428	0.132	64,795,849	5,626,421	**9.5%**
Total				**81,411,583**		**88,563,093**	**7,151,509**	
Labrador Industrial[3] []	2,943,600	$/kW	1.61	4,739,196	1.93	5,671,926	932,730	**19.7%**

[1] Average unit revenues expressed in dollars per kWh based on July 1, 2017 rates.

[2] Average unit revenues expressed in dollars per kWh based on 2018 Cost of Service Study results.

[3] Includes both Transmission and Generation Cost Recovery

Chapter 5 – Schedule II

2019 Required Increase Relative to Existing Rates

Newfoundland and Labrador Hydro
2019 Required Increase Relative to Existing Rates[1]
Newfoundland Power

	2019 Billing Units at 2018 First Block Size	2019 Test Year Billing Units	Unit	Existing Rate[2]	Existing Billings $	2019 Proposed Final	$	$ Change	Percent Change Utility	Percent Change Consumer
Demand (kWs)	15,164,832	15,158,472	$/kW/mo	4.75	72,032,952	5.25	79,581,978			
Energy (MWhs)	3,000,000	3,480,000	¢/kWh	2.226	66,780,000	3.821	132,970,800			
Energy (MWhs)	2,833,600	2,353,600	¢/kWh	10.422	295,317,792	14.141	332,822,576			
Total Base Rate					434,130,744		545,375,354			
RSP Recovery Adjustment-Normal		5,833,600	¢/kWh	(0.132)	(7,700,352)	(0.132)	(7,700,352)			
RSP Mitigation impact		5,833,600	¢/kWh	(0.911)	(53,144,096)	(0.911)	(53,144,096)			
RSP Fuel Rider		5,833,600	¢/kWh	0.672	39,201,792		-			
CDM Recovery Adjustment		5,833,600	¢/kWh	0.019	1,108,384	0.019	1,108,384			
Total					**413,596,472**		**485,639,290**	**72,042,818**	**17.4%**	**11.8%**

[1] Hydro has assumed continuation of the existing RSP and CDM recovery riders that became effective July 1, 2017.
[2] Based on rates effective July 1, 2017.

Newfoundland and Labrador Hydro
2019 Required Increase Relative to Existing Rates[1]
Island Industrial Customers

	2019 Test Year Billing Units	Unit	Existing Rate[2]	Existing Billings $	2019 Proposed Final	$	$ Change	Percent Change
Demand (kWs)	1,158,000	$/kW/mo	7.99	9,252,420	11.12	12,876,960		
Energy - Firm (MWhs)	743,300	¢/kWh	3.971	29,516,443	4.792	35,618,936		
Spec. Assigned		$	1,639,833	1,639,833	1,277,206	1,277,206		
Total Base Rate				40,408,696		49,773,102		
RSP: Current Plan	743,300	¢/kWh	(0.373)	(2,772,509)	(0.373)	(2,772,509)		
RSP: Current Plan Mitigation	743,300	¢/kWh	(0.313)	(2,326,529)	(0.313)	(2,326,529)		
RSP: Fuel Rider	743,300	¢/kWh	0.625	4,645,625		-		
CDM Recovery Adjustment	743,300	¢/kWh	0.009	66,897	0.009	66,897		
Total				**40,022,180**		**44,740,961**	**4,718,781**	**11.8%**

[1] Hydro has assumed continuation of the existing RSP and CDM recovery riders that became effective July 1, 2017.

[2] Based on rates effective July 1, 2017.

Newfoundland and Labrador Hydro
2019 Required Increase Relative to Existing Rates
Remaining Classes

	2019 Test Year Billing Units	Unit	Existing Average Unit Cost[1]	Existing Billings $	Proposed Average Unit Cost[2]	Revenue Requirement 2019 Cost of Service	$ Change	Percent Change
Rural Labrador Interconnected	655,748,310	$/kWh	0.031	20,174,635	0.034	22,558,580	2,383,944	**11.8%**
Hydro Rural Government	2,396,960	$/kWh	0.866	2,075,306	1.056	2,530,900	455,593	**22.0%**
Hydro Rural Other	486,723,690	$/kWh	0.121	58,715,229	0.135	65,630,709	6,915,480	**11.8%**
Total				**80,965,171**		**90,720,188**	**9,755,018**	
Labrador Industrial[3] []	2,940,000	$/kW	1.61	4,733,400	2.33	6,860,190	2,126,790	**44.9%**

[1] Average unit revenues expressed in dollars per kWh based on July 1, 2017 rates.

[2] Average unit revenues expressed in dollars per kWh based on 2019 Proposed Final Rates excluding the 2018 revenue deficiency.

[3] Includes both Transmission and Generation Cost Recovery. The unit cost per kW is calculated based on Power on Order.

Chapter 5 – Schedule III

Customer Rate Impacts – 2018 Proposed Interim Rates

Newfoundland and Labrador Hydro
Customer Rate Impacts - 2018 Interim Rates[1]
Newfoundland Power

	2018 Test Year Billing Units	Unit	Existing Rate[2]	Existing Billings $	Proposed Interim Rate	Proposed Interim Billings	$ Change	Percent Utility Increase	Percent Customer Increase
Demand (kWs)	15,164,832	$/kW/mo	4.75	72,032,952	5.00	75,824,160			
Energy (MWhs)	3,000,000	¢/kWh	2.226	66,780,000	3.443	103,290,000			
Energy (MWhs)	2,824,500	¢/kWh	10.422	294,369,390	10.422	294,369,390			
Total Base Rate				433,182,342		473,483,550			
RSP Recovery Adjustment-Normal	5,824,500	¢/kWh	(0.132)	(7,688,340)	(0.132)	(7,688,340)			
RSP Mitigation impact	5,824,500	¢/kWh	(0.911)	(53,061,195)	(0.911)	(53,061,195)			
RSP Fuel Rider	5,824,500	¢/kWh	0.672	39,140,640	0.672	39,140,640			
CDM Recovery Adjustment	5,824,500	¢/kWh	0.019	1,106,655	0.019	1,106,655			
Total				**412,680,102**		**452,981,310**	**40,301,208**	**9.8%**	**6.6%**

[1] Hydro has assumed continuation of the existing RSP and CDM recovery riders that became effective July 1, 2017.
[2] Based on rates effective July 1, 2017.

Newfoundland and Labrador Hydro
Customer Rate Impacts - 2018 Interim Rates[1]
Total Island Industrial Customers

	2018 Test Year Billing Units	Unit	Existing Rate[2]	Existing Billings $	Proposed Interim Rate	Proposed Interim Billing	$ Change	Percent Change
Demand (kWs)	1,170,000	$/kW/mo	7.99	9,348,300	9.93	11,618,100		
Energy - Firm (MWhs)	726,000	¢/kWh	3.971	28,829,460	3.971	28,829,460		
Energy - Interim (MWhs)	726,000	¢/kWh			0.100	726,000		
Spec. Assigned		$	1,639,833	1,639,833	1,132,670	1,132,670		
Total Base Rate				39,817,593		42,306,230		
RSP: Current Plan	726,000	¢/kWh	(0.373)	(2,707,980)	(0.373)	(2,707,980)		
RSP: Current Plan Mitigation	726,000	¢/kWh	(0.313)	(2,272,380)	(0.313)	(2,272,380)		
RSP: Fuel Rider	726,000	¢/kWh	0.625	4,537,500	0.625	4,537,500		
CDM Recovery Adjustment	726,000	¢/kWh	0.009	65,340	0.009	65,340		
Total				**39,440,073**		**41,928,710**	**2,488,637**	**6.3%**

[1] Hydro has assumed continuation of the existing RSP and CDM recovery riders that became effective July 1, 2017.

[2] Based on rates effective July 1, 2017.

Newfoundland and Labrador Hydro
Customer Rate Impacts - 2018 Interim Rates[1]
Praxair

	2018 Test Year Billing Units	Unit	Existing Rate[2]	Existing Billings $	Proposed Interim Rate	Proposed Interim Billing	$ Change	Percent Change
Demand (kWs)	72,000	$/kW/mo	7.99	575,280	9.93	714,960		
Energy - Firm (MWhs)	50,800	¢/kWh	3.971	2,017,268	3.971	2,017,268		
Energy - Interim (MWhs)	50,800	¢/kWh			0.100	50,800		
Spec. Assigned		$		-	-	-		
Total Base Rate				2,592,548		2,783,028		
RSP: Current Plan	50,800	¢/kWh	(0.373)	(189,484)	(0.373)	(189,484)		
RSP: Current Plan Mitigation	50,800	¢/kWh	(0.313)	(159,004)	(0.313)	(159,004)		
RSP: Fuel Rider	50,800	¢/kWh	0.625	317,500	0.625	317,500		
CDM Recovery Adjustment	50,800	¢/kWh	0.009	4,572	0.009	4,572		
Total				**2,566,132**		**2,756,612**	**190,480**	**7.4%**

[1] Hydro has assumed continuation of the existing RSP and CDM recovery riders that became effective July 1, 2017.

[2] Based on rates effective July 1, 2017.

Newfoundland and Labrador Hydro
Customer Rate Impacts - 2018 Interim Rates[1]
Vale

	2018 Test Year Billing Units	Unit	Existing Rate[2]	Existing Billings $	Proposed Interim Rate	Proposed Interim Billing	$ Change	Percent Change
Demand (kWs)	624,000	$/kW/mo	7.99	4,985,760	9.93	6,196,320		
Energy - Firm (MWhs)	380,900	¢/kWh	3.971	15,125,539	3.971	15,125,539		
Energy - Interim (MWhs)	380,900	¢/kWh			0.100	380,900		
Spec. Assigned		$	480,243	480,243	165,774	165,774		
Total Base Rate				20,591,542		21,868,533		
RSP: Current Plan	380,900	¢/kWh	(0.373)	(1,420,757)	(0.373)	(1,420,757)		
RSP: Current Plan Mitigation	380,900	¢/kWh	(0.313)	(1,192,217)	(0.313)	(1,192,217)		
RSP: Fuel Rider	380,900	¢/kWh	0.625	2,380,625	0.625	2,380,625		
CDM Recovery Adjustment	380,900	¢/kWh	0.009	34,281	0.009	34,281		
Total				**20,393,474**		**21,670,465**	**1,276,991**	**6.3%**

[1] Hydro has assumed continuation of the existing RSP and CDM recovery riders that became effective July 1, 2017.

[2] Based on rates effective July 1, 2017.

Newfoundland and Labrador Hydro

Customer Rate Impacts - 2018 Interim Rates[1]

CBPP

	2018 Test Year Billing Units	Unit	Existing Rate[2]	Existing Billings $	Proposed Interim Rate	Proposed Interim Billing	$ Change	Percent Change
Demand (kWs)	84,000	$/kW/mo	7.99	671,160	9.93	834,120		
Energy - Firm (MWhs)	40,000	¢/kWh	3.971	1,588,400	3.971	1,588,400		
Energy - Interim (MWhs)	40,000	¢/kWh			0.100	40,000		
Spec. Assigned		$	870,898	870,898	732,673	732,673		
Total Base Rate				3,130,458		3,195,193		
RSP: Current Plan	40,000	¢/kWh	(0.373)	(149,200)	(0.373)	(149,200)		
RSP: Current Plan Mitigation	40,000	¢/kWh	(0.313)	(125,200)	(0.313)	(125,200)		
RSP: Fuel Rider	40,000	¢/kWh	0.625	250,000	0.625	250,000		
CDM Recovery Adjustment	40,000	¢/kWh	0.009	3,600	0.009	3,600		
Total				**3,109,658**		**3,174,393**	**64,735**	**2.1%**

[1] Hydro has assumed continuation of the existing RSP and CDM recovery riders that became effective July 1, 2017.

[2] Based on rates effective July 1, 2017.

Newfoundland and Labrador Hydro
Customer Rate Impacts - 2018 Interim Rates[1]
NARL

	2018 Test Year Billing Units	Unit	Existing Rate[2]	Existing Billings $	Proposed Interim Rate	Proposed Interim Billing	$ Change	Percent Change
Demand (kWs)	384,000	$/kW/mo	7.99	3,068,160	9.93	3,813,120		
Energy - Firm (MWhs)	253,100	¢/kWh	3.971	10,050,601	3.971	10,050,601		
Energy - Interim (MWhs)	253,100	¢/kWh			0.100	253,100		
Spec. Assigned		$	89,293	89,293	183,050	183,050		
Total Base Rate				13,208,054		14,299,871		
RSP: Current Plan	253,100	¢/kWh	(0.373)	(944,063)	(0.373)	(944,063)		
RSP: Current Plan Mitigation	253,100	¢/kWh	(0.313)	(792,203)	(0.313)	(792,203)		
RSP: Fuel Rider	253,100	¢/kWh	0.625	1,581,875	0.625	1,581,875		
CDM Recovery Adjustment	253,100	¢/kWh	0.009	22,779	0.009	22,779		
Total				**13,076,442**		**14,168,259**	**1,091,817**	**8.3%**

[1] Hydro has assumed continuation of the existing RSP and CDM recovery riders that became effective July 1, 2017.

[2] Based on rates effective July 1, 2017.

Newfoundland and Labrador Hydro

Customer Rate Impacts - 2018 Interim Rates[1]

Teck

	2018 Test Year Billing Units	Unit	Existing Rate[2]	Existing Billings $	Proposed Interim Rate	Proposed Interim Billing	$ Change	Percent Change
Demand (kWs)	6,000	$/kW/mo	7.99	47,940	9.93	59,580		
Energy - Firm (MWhs)	1,200	¢/kWh	3.971	47,652	3.971	47,652		
Energy - Interim (MWhs)	1,200	¢/kWh			0.100	1,200		
Spec. Assigned		$	199,399	199,399	51,173	51,173		
Total Base Rate				294,991		159,605		
RSP: Current Plan	1,200	¢/kWh	(0.373)	(4,476)	(0.373)	(4,476)		
RSP: Current Plan Mitigation	1,200	¢/kWh	(0.313)	(3,756)	(0.313)	(3,756)		
RSP: Fuel Rider	1,200	¢/kWh	0.625	7,500	0.625	7,500		
CDM Recovery Adjustment	1,200	¢/kWh	0.009	108	0.009	108		
Total				**294,367**		**158,981**	**(135,386)**	**-46.0%**

[1] Hydro has assumed continuation of the existing RSP and CDM recovery riders that became effective July 1, 2017.

[2] Based on rates effective July 1, 2017.

Newfoundland and Labrador Hydro
Customer Rate Impacts - 2018 Interim Rates
Remaining Classes

	2018 Test Year Billing Units	Unit	Existing Unit Rate[1]	Existing Billings $	Proposed 2018 Interim Rates[2]	Interim Billings ($)	$ Change	Percent Change
Rural Labrador Interconnected	656,143,630	$/kWh	0.030	19,981,254	0.0320	20,868,489	887,234	**4.4%**
Hydro Rural Government	2,397,490	$/kWh	0.866	2,075,526	0.943	2,261,032	185,506	**8.9%**
Hydro Rural Other	491,216,300	$/kWh	0.120	59,169,428	0.128	63,074,611	3,905,182	**6.6%**
Total				**81,226,209**		**86,204,131**	**4,977,923**	
Labrador Industrial[3] []	2,943,600	$/kW	1.61	4,739,196	1.85	5,456,848	717,652	**15.1%**

[1] Average unit revenues expressed in dollars per kWh based on July 1, 2017 rates.

[2] Average unit revenues expressed in dollars per kWh based on Proposed 2018 Interim Rates.

[3] Includes both Transmission and Generation Cost Recovery

Chapter 5 – Schedule IV

Customer Rate Impacts - 2019 Proposed Rates

Newfoundland and Labrador Hydro
Customer Rate Impacts - Proposed 2019 Final Rates[1]
Newfoundland Power

	2019 Billing Units at 2018 First Block Size	2019 Test Year Billing Units	Unit	2018 Rates Interim	2019 Billings (Interim Rates)	Proposed 2019 Final Rates	2019 Final Billings ($)	$ Change	Percent Change Utility	Percent Change Consumer
Demand (kWs)	15,143,172	15,158,472	$/kW/mo	5.00	75,715,860	5.25	79,581,978			
Energy (MWhs)	3,000,000	3,480,000	¢/kWh	3.443	103,290,000	3.821	132,970,800			
Energy (MWhs)	2,833,600	2,353,600	¢/kWh	10.422	295,317,792	14.141	332,822,576			
2018 Revenue Deficiency			$			902,506	10,830,072			
Total Base Rate					474,323,652		556,205,426			
RSP Recovery Adjustment-Normal		5,833,600	¢/kWh	(0.132)	(7,700,352)	(0.132)	(7,700,352)			
RSP Mitigation impact		5,833,600	¢/kWh	(0.911)	(53,144,096)	(0.911)	(53,144,096)			
RSP Fuel Rider		5,833,600	¢/kWh	0.672	39,201,792		-			
CDM Recovery Adjustment		5,833,600	¢/kWh	0.019	1,108,384	0.019	1,108,384			
Total					**453,789,380**		**496,469,362**	**42,679,982**	**9.4%**	**6.4%**

[1] Hydro has assumed continuation of the existing RSP and CDM recovery riders that became effective July 1, 2017.

Newfoundland and Labrador Hydro

Customer Rate Impacts - Proposed 2019 Final Rates[1]

Island Industrial Customers

	2019 Test Year Billing Units	Unit	2018 Interim Rates	Interim Billings ($)	Proposed Final Rate	2019 Final Billings ($)	$ Change	Percent Change
Demand (kWs)	1,158,000	$/kW/mo	9.93	11,498,940	11.12	12,876,960		
Demand Deficiency (kWs)	1,158,000	$/kW/mo	-	-	0.50	579,000		
Energy - Firm (MWhs)	743,300	¢/kWh	3.971	29,516,443	4.792	35,618,936		
Energy - Interim Rider (MWhs)	743,300	¢/kWh	0.100	743,300	-	-		
Energy Deficiency (MWhs)	743,300	¢/kWh	-	-	0.025	185,825		
Spec. Assigned		$	1,132,670	1,132,670	1,277,206	1,277,206		
Total Base Rate				42,891,353		50,537,927		
RSP: Current Plan	743,300	¢/kWh	(0.373)	(2,772,509)	(0.373)	(2,772,509)		
RSP: Current Plan Mitigation	743,300	¢/kWh	(0.313)	(2,326,529)	(0.313)	(2,326,529)		
RSP: Fuel Rider	743,300	¢/kWh	0.625	4,645,625	-	-		
CDM Recovery Adjustment	743,300	¢/kWh	0.009	66,897	0.009	66,897		
Total				**42,504,837**		**45,505,786**	**3,000,949**	**7.1%**

[1] Hydro has assumed continuation of the existing RSP and CDM recovery riders that became effective July 1, 2017.

Newfoundland and Labrador Hydro
Customer Rate Impacts - Proposed 2019 Final Rates[1]
Praxair

	2019 Test Year Billing Units	Unit	2018 Interim Rates	Interim Billings ($)	Proposed Final Rate	2019 Final Billings ($)	$ Change	Percent Change
Demand (kWs)	72,000	$/kW/mo	9.93	714,960	11.12	800,640		
Demand Deficiency (kWs)	72,000	$/kW/mo	-	-	0.50	36,000		
Energy - Firm (MWhs)	50,800	¢/kWh	3.971	2,017,268	4.792	2,434,336		
Energy - Interim Rider (MWhs)	50,800	¢/kWh	0.100	50,800	-	-		
Energy Deficiency (MWhs)	50,800	¢/kWh	-	-	0.025	12,700		
Spec. Assigned		$	-	-	-	-		
Total Base Rate				2,783,028		3,283,676		
RSP: Current Plan	50,800	¢/kWh	(0.373)	(189,484)	(0.373)	(189,484)		
RSP: Current Plan Mitigation	50,800	¢/kWh	(0.313)	(159,004)	(0.313)	(159,004)		
RSP: Fuel Rider	50,800	¢/kWh	0.625	317,500	-	-		
CDM Recovery Adjustment	50,800	¢/kWh	0.009	4,572	0.009	4,572		
Total				**2,756,612**		**2,939,760**	**183,148**	**6.6%**

[1] Hydro has assumed continuation of the existing RSP and CDM recovery riders that became effective July 1, 2017.

Newfoundland and Labrador Hydro
Customer Rate Impacts - Proposed 2019 Final Rates[1]
Vale

	2019 Test Year Billing Units	Unit	2018 Interim Rates	Interim Billings ($)	Proposed Final Rate	2019 Final Billings ($)	$ Change	Percent Change
Demand (kWs)	624,000	$/kW/mo	9.93	6,196,320	11.12	6,938,880		
Demand Deficiency (kWs)	624,000	$/kW/mo	-	-	0.50	312,000		
Energy - Firm (MWhs)	393,800	¢/kWh	3.971	15,637,798	4.792	18,870,896		
Energy - Interim Rider (MWhs)	393,800	¢/kWh	0.100	393,800	-	-		
Energy Deficiency (MWhs)	393,800	¢/kWh	-	-	0.025	98,450		
Spec. Assigned	393,800	$	165,774	165,774	170,233	170,233		
Total Base Rate				22,393,692		26,390,459		
RSP: Current Plan	393,800	¢/kWh	(0.373)	(1,468,874)	(0.373)	(1,468,874)		
RSP: Current Plan Mitigation	393,800	¢/kWh	(0.313)	(1,232,594)	(0.313)	(1,232,594)		
RSP: Fuel Rider	393,800	¢/kWh	0.625	2,461,250		-		
CDM Recovery Adjustment	393,800	¢/kWh	0.009	35,442	0.009	35,442		
Total				**22,188,916**		**23,724,433**	**1,535,517**	**6.9%**

[1] Hydro has assumed continuation of the existing RSP and CDM recovery riders that became effective July 1, 2017.

Newfoundland and Labrador Hydro
Customer Rate Impacts - Proposed 2019 Final Rates[1]
CBPP

	2019 Test Year Billing Units	Unit	2018 Interim Rates	Interim Billings ($)	Proposed Final Rate	2019 Final Billings ($)	$ Change	Percent Change
Demand (kWs)	72,000	$/kW/mo	9.93	714,960	11.12	800,640		
Demand Deficiency (kWs)	72,000	$/kW/mo	-	-	0.50	36,000		
Energy - Firm (MWhs)	34,100	¢/kWh	3.971	1,354,111	4.792	1,634,072		
Energy - Interim Rider (MWhs)	34,100	¢/kWh	0.100	34,100	-	-		
Energy Deficiency (MWhs)	34,100	¢/kWh	-	-	0.025	8,525		
Spec. Assigned		$	732,673	732,673	861,911	861,911		
Total Base Rate				2,835,844		3,341,148		
RSP: Current Plan	34,100	¢/kWh	(0.373)	(127,193)	(0.373)	(127,193)		
RSP: Current Plan Mitigation	34,100	¢/kWh	(0.313)	(106,733)	(0.313)	(106,733)		
RSP: Fuel Rider	34,100	¢/kWh	0.625	213,125		-		
CDM Recovery Adjustment	34,100	¢/kWh	0.009	3,069	0.009	3,069		
Total				**2,818,112**		**3,110,291**	**292,179**	**10.4%**

[1] Hydro has assumed continuation of the existing RSP and CDM recovery riders that became effective July 1, 2017.

Newfoundland and Labrador Hydro

Customer Rate Impacts - Proposed 2019 Final Rates[1]

NARL

	2019 Test Year Billing Units	Unit	2018 Interim Rates	Interim Billings ($)	Proposed Final Rate	2019 Final Billings ($)	$ Change	Percent Change
Demand (kWs)	384,000	$/kW/mo	9.93	3,813,120	11.12	4,270,080		
Demand Deficiency (kWs)	384,000	$/kW/mo	-	-	0.50	192,000		
Energy - Firm (MWhs)	263,400	¢/kWh	3.971	10,459,614	4.792	12,622,128		
Energy - Interim Rider (MWhs)	263,400	¢/kWh	0.100	263,400	-	-		
Energy Deficiency (MWhs)	263,400	¢/kWh	-	-	0.025	65,850		
Spec. Assigned		$	183,050	183,050	193,496	193,496		
Total Base Rate				14,719,184		17,343,554		
RSP: Current Plan	263,400	¢/kWh	(0.373)	(982,482)	(0.373)	(982,482)		
RSP: Current Plan Mitigation	263,400	¢/kWh	(0.313)	(824,442)	(0.313)	(824,442)		
RSP: Fuel Rider	263,400	¢/kWh	0.625	1,646,250		-		
CDM Recovery Adjustment	263,400	¢/kWh	0.009	23,706	0.009	23,706		
Total				**14,582,216**		**15,560,336**	**978,120**	**6.7%**

[1] Hydro has assumed continuation of the existing RSP and CDM recovery riders that became effective July 1, 2017.

Newfoundland and Labrador Hydro

Customer Rate Impacts - Proposed 2019 Final Rates[1]

Teck

	2019 Test Year Billing Units	Unit	2018 Interim Rates	Interim Billings ($)	Proposed Final Rate	2019 Final Billings ($)	$ Change	Percent Change
Demand (kWs)	6,000	$/kW/mo	9.93	59,580	11.12	66,720		
Demand Deficiency (kWs)	6,000	$/kW/mo	-	-	0.50	3,000		
Energy - Firm (MWhs)	1,200	¢/kWh	3.971	47,652	4.792	57,504		
Energy - Interim Rider (MWhs)	1,200	¢/kWh	0.100	1,200	-	-		
Energy Deficiency (MWhs)	1,200	¢/kWh	-	-	0.025	300		
Spec. Assigned		$	51,173	51,173	51,566	51,566		
Total Base Rate				159,605		179,090		
RSP: Current Plan	1,200	¢/kWh	(0.373)	(4,476)	(0.373)	(4,476)		
RSP: Current Plan Mitigation	1,200	¢/kWh	(0.313)	(3,756)	(0.313)	(3,756)		
RSP: Fuel Rider	1,200	¢/kWh	0.625	7,500		-		
CDM Recovery Adjustment	1,200	¢/kWh	0.009	108	0.009	108		
Total				**158,981**		**170,966**	**11,985**	**7.5%**

[1] Hydro has assumed continuation of the existing RSP and CDM recovery riders that became effective July 1, 2017.

Newfoundland and Labrador Hydro
Customer Rate Impacts - Proposed 2019 Final Rates
Remaining Classes

	2019 Test Year Billing Units	Unit	2018 Interim Rates[1]	2019 Interim Billings ($)	Proposed 2019 Final Rates[2]	2019 Final Billings ($)	$ Change	Percent Change
Rural Labrador Interconnected	655,751,310	$/kWh	0.032	20,876,692	0.034	22,597,240	1,720,548	**8.2%**
Hydro Rural Government	2,396,960	$/kWh	0.943	2,260,793	1.073	2,571,889	311,096	**13.8%**
Hydro Rural Other	486,719,690	$/kWh	0.129	62,590,434	0.137	66,596,222	4,005,788	**6.4%**
Total				**85,727,920**		**91,765,352**	**6,037,432**	
Labrador Industrial[3] []	2,940,000	$/kW	1.85	5,451,487	2.38	6,996,780	1,545,292	**28.3%**

[1] Average unit revenues expressed in dollars per kWh based on 2018 Proposed Interim Rates.

[2] Average unit revenues expressed in dollars per kWh based on Proposed 2019 Final Rates.

[3] Includes both Transmission and Generation Cost Recovery

Chapter 5 – Schedule V

Proposed Revision to RSP Rules

Newfoundland and Labrador Hydro
Proposed Revision to RSP Rules

Current language:

Newfoundland Power Rate Change Impacts:

This component is calculated for Hydro's rural customers whose rates are directly or indirectly impacted by Newfoundland Power's rate changes, with the following formula:

(M – N) x O

Where:

M = Cost of Service rate
N = Existing Rate
O = Actual Units (kWh, bills, billing demand)

Proposed language:

Newfoundland Power Rate Change Impacts:

This component is calculated for Hydro's rural customers whose rates are directly or indirectly impacted by Newfoundland Power's rate changes, with the following formula:

(M – N) x O

Where:

M = Cost of Service rate
N = Existing Rate
O = Test Year Units (kWh, bills, billing demand)

Chapter 5 – Schedule VI

Proposed Revision to Regulations

Newfoundland and Labrador Hydro
Proposed Revision to Regulations

Charges – Section 9(b)

Current:

Where a Customer requires Service for a period of less than three (3) years, the Customer shall pay Hydro in advance a "Temporary Connection Fee". The Temporary Connection Fee is calculated as the estimated labour cost of installing and removing lines and equipment necessary for the Service plus the estimated cost of non-salvageable material.

Proposed:

Where a Customer requires Service for a period of less than three (3) years, the Customer shall pay Hydro [] a "Temporary Connection Fee". The Temporary Connection Fee is calculated as the estimated labour cost of installing and removing lines and equipment necessary for the Service plus the estimated cost of non-salvageable material. The payment may be required in advance or, subject to credit approval, billed to the Customer.

Charges – Section 9(c)

Current:

Where special facilities are required or requested by the Customer or any facility is relocated at the request of the Customer, the Customer shall pay Hydro in advance the estimated additional cost of providing the special facilities and the estimated cost of the relocation less any betterment.

Proposed:

Where special facilities are required or requested by the Customer or any facility is relocated at the request of the Customer, the Customer shall pay Hydro [] the estimated additional cost of providing the special facilities and the estimated cost of the relocation less any betterment. The payment may be required in advance or, subject to credit approval, billed to the Customer.

Policies for Automatic Rate Changes – Section 16(a)

Current:

Island Interconnected System:

(i) As Newfoundland Power changes its rates, Hydro will automatically adjust all rates such that these customers pay the same rates as Newfoundland Power customers.

Proposed:

Island Interconnected System:

(i) As Newfoundland Power changes its rates, Hydro will automatically adjust all rates such that these customers pay the same rates as Newfoundland Power customers.

(ii) Rates for the Burgeo school and library will increase or decrease by the average rate of change granted by Newfoundland Power from time to time, excluding: Newfoundland Power's changes for the July 1st Municipal Tax and Rate Stabilization adjustments and any Fuel Rider adjustments.

Chapter 5 – Schedule VII

Existing and Proposed Rates – Labrador and Government Diesel

Newfoundland and Labrador Hydro
Existing and Proposed Rates – Labrador and Government Diesel

Diesel - Government Departments

	Current Rate	Proposed January 1, 2018 Interim Rate	Proposed January 1, 2019 Rates
Rate 1.2G Domestic Diesel			
Basic Customer Charge (per month)	55.69	60.70	65.40
Energy (cents per kWh)	89.164	97.189	115.447
Rate 2.1G General Service Diesel (0-10 kW)			
Basic Customer Charge (per month)	59.76	65.14	69.79
Energy (cents per kWh)	81.367	88.690	98.749
Rate 2.2G General Service Diesel (Over 10 kw)			
Basic Customer Charge (per month)	73.76	80.40	88.70
Demand (dollars per kW)	59.83	65.21	75.62
Energy (cents per kWh)	60.033	65.436	73.089
Street and Area Lighting Diesel 4.1G ($/month)			
Mercury Vapour			
250 W (9,400 lumens)	85.29	92.97	110.74
High Pressure Sodium			
100 W (8,600 lumens)	57.28	62.44	74.38
150W (14,400 lumens)	85.29	92.97	110.74

Newfoundland and Labrador Hydro
Existing and Proposed Rates – Labrador and Government Diesel

Labrador Interconnected

	Current Rate	Proposed January 1, 2018 Interim Rate	Proposed January 1, 2019 Rates
Rate 1.1 Domestic			
Basic Customer Charge ($ per month)	7.09	7.41	8.03
Energy (¢ per kWh)	3.255	3.402	3.688
Rate 2.1 General Service (0-10 kW)			
Basic Customer Charge ($ per month)			
Unmetered ($ per month)	10.37	10.84	11.75
Single Phase ($ per month)	6.41	6.84	7.75
Three Phase ($ per month)	16.32	16.84	17.75
Energy (¢ per kWh)	5.092	5.323	5.777
Rate 2.2 General Service (10-100 kw)			
Basic Customer Charge ($ per month)			
Unmetered ($ per month)	10.37	10.84	11.75
Single Phase ($ per month)	6.41	6.84	7.75
Three Phase ($ per month)	16.32	16.84	17.75
Demand ($ per kW)	1.76	1.84	1.99
Energy (¢ per kWh)	2.417	2.527	2.742
Rate 2.3 General Service (110-1000 kva)			
Demand ($ per kW)	1.97	2.06	2.23
Energy (¢ per kWh)	2.090	2.184	2.366
Rate 2.4 General Service (Over 1000 kva)			
Demand ($ per kW)	1.71	1.79	1.91
Energy (¢ per kWh)	1.725	1.799	1.948
Street and Area Lighting			
250W Mercury Vapour ($ per month)	15.42	15.42	15.42
100W High Pressure Sodium ($ per month)	11.43	11.43	11.43
150W High Pressure Sodium ($ per month)	15.42	15.42	15.42
250W High Pressure Sodium ($ per month)	20.34	20.34	20.34
400W High Pressure Sodium ($ per month)	26.28	26.28	26.28
Wood Poles ($ per month)	3.88	3.88	3.88
100W High Pressure Sodium Closed ($ per month)	7.71	7.71	7.71
100W High Pressure Sodium ($ per month)	4.68	4.68	4.68
Wood Poles ($ per month)	3.71	3.71	3.71

Newfoundland and Labrador Hydro
Existing and Proposed Rates – Labrador and Government Diesel

Labrador Industrial Transmission

Current Rate (per kW per month)

100% of Power on Order	$1.19

Proposed Rates Reflecting Proposed Methodology (per kW per month)

	Proposed January 1, 2018 Interim Rate	Proposed January 1, 2019 Rates
First Block (90% of Power on Order)	$1.34	$1.86
Metered Demand in Excess of First Block	$2.83	$3.95

Chapter 5 – Schedule VIII

Labrador Industrial Transmission Costs

Newfoundland and Labrador Hydro
Labrador Industrial Transmission Costs

2018 Labrador Industrial Embedded Transmission Demand Costs

Total Labrador Interconnected Transmission Demand Cost[1]	$7,320,717
Labrador Industrial Allocation based on Single Coincident Peak[2]	58.02%
Allocated Transmission Demand Cost[3]	$4,247,172
Power on Order (kW)[4]	245,300
Annual Cost ($ per kW)[5]	$17.31
Monthly Cost ($ per kW)[6]	$1.44

2019 Labrador Industrial Embedded Transmission Demand Costs

Total Labrador Interconnected Transmission Demand Cost[7]	$9,391,411
Labrador Industrial Allocation based on Single Coincident Peak[8]	58.10%
Allocated Transmission Demand Cost[9]	$5,456,470
Power on Order (kW)[10]	245,000
Annual Cost ($ per kW)[11]	$22.27
Monthly Cost ($ per kW)[12]	$1.86

[1] Exhibit 14, 2018 Test Year Cost of Service Study, Schedule 2.1E, Page 1 of 2, Line 23, Column 5.
[2] Exhibit 14, 2018 Test Year Cost of Service Study, Schedule 3.1E, Page 1 of 2, Line 14, Column 5.
[3] Exhibit 14, 2018 Test Year Cost of Service Study, Schedule 3.2E, Page 3 of 4, Line 40, Column 5.
[4] Exhibit 14, 2018 Test Year Cost of Service Study, Schedule 1.3.2, Page 3 of 3, Line 8, Column 2 divided by 12.
[5] Annual Cost = Allocated Transmission Demand Cost / Power on Order
Annual Cost = ($4,247,172/245,300) = $17.31
[6] Monthly Cost = Annual Cost / 12 months
Monthly Cost = ($17.31/12 months) = $1.44
[7] Exhibit 15, 2019 Test Year Cost of Service Study, Schedule 2.1E, Page 1 of 2, Line 23, Column 5.
[8] Exhibit 15, 2019 Test Year Cost of Service Study, Schedule 3.1E, Page 1 of 2, Line 14, Column 5.
[9] Exhibit 15, 2019 Test Year Cost of Service Study, Schedule 3.2E, Page 3 of 4, Line 40, Column 5.
[10] Exhibit 15, 2019 Test Year Cost of Service Study, Schedule 1.3.2, Page 3 of 3, Line 8, Column 2 divided by 12.
[11] Annual Cost = Allocated Transmission Demand Cost / Power on Order
Annual Cost = ($5,456,470/245,000) = $22.27
[12] Monthly Cost = Annual Cost / 12 months
Monthly Cost = ($22.27/12) = $1.86

Chapter 6 – Supplemental Evidence

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List of Schedules

Chapter 6 Supplemental Evidence

6.1. Background

As set out in Chapters 1 and 5, Hydro is proposing to manage customer rates in advance of its next General Rate Application (GRA) when it will be proposing rates to begin recovery of the Muskrat Falls Project costs.[1]

The availability of the LIL, LTA, and the Maritime Link transmission lines, expected in 2018, will provide Hydro with off-island supply options for the Island electrical system from 2018 to 2020 while the construction of the Muskrat Falls Plant continues. With the availability of these transmission components, there is a significant opportunity to reduce Holyrood generation by using off-island power purchases in 2018, 2019, and 2020.

Hydro is proposing that the supply cost forecast used in determining revenue requirements for the 2018 and 2019 Test Years reflects the continued use of No. 6 fuel at the Holyrood Thermal Generating Station (Holyrood), as if the Island remained isolated from the North American grid. Hydro is also proposing to establish a deferral account which will include the cumulative net savings from accessing off-island power purchases prior to full commissioning of the Muskrat Falls Project.[2]

[1] The Muskrat Falls Project is comprised of three main components: (i) the Muskrat Falls Hydroelectric Generating Facility (Muskrat Falls Plant); (ii) the Labrador-Island Link (the LIL) transmission assets which will carry electricity from the Muskrat Falls Plant to the island of Newfoundland, and (iii) the Labrador Transmission Assets (the LTA), which are comprised of two transmission lines to transmit power between the Muskrat Falls Plant and the existing 5,428 MW hydroelectric facility in Churchill Falls. In conjunction with the Muskrat Falls Project, Emera Inc. is building the Maritime Link which will connect the island of Newfoundland and Nova Scotia.

[2] The proposed deferral account will include the No. 6 fuel savings from off-island power purchases and the costs attributable to off-island power purchases, including transmission costs for delivery.

At its next GRA,[3] Hydro will be proposing increased customer rates to begin recovery of the cost of the Muskrat Falls Project upon completion of its full commissioning expected in late 2020.[4] Given that future rates will increase to provide recovery of the costs of the Muskrat Falls Project, Hydro considers it reasonable that those same future customers responsible for the recovery of the Muskrat Falls Project costs receive the benefit from any savings that can be achieved through early use of the LIL and LTA. Therefore, Hydro is proposing the net savings from off-island power purchases prior to Muskrat Falls Project commissioning be set aside to be used to reduce the customer rate impact of the future recovery of the costs of the Muskrat Falls Project.

6.2. Accounting Treatment of Muskrat Falls Project Costs

The original plan for the Muskrat Falls Project was that the commissioning of transmission and generation facilities would coincide. However, in June 2016, Nalcor Energy (Nalcor) announced that construction of the Muskrat Falls Plant was delayed while the LIL and LTA are expected to be available approximately 2 years in advance of the Muskrat Falls Plant. The use of the LIL and LTA during this time period will benefit Hydro's customers through improved reliability and a reduction in supply costs.

Nalcor's accounting requirements relating to the recognition of depreciation and interest expense on the LIL and LTA assets during the interim use period prior to full commissioning of the Muskrat Falls Project are currently under review and Nalcor is actively working on this issue. Should Nalcor be required to recognize these costs as an expense as a result of transmission assets being used in advance of the full project completion, it would be reasonable for Hydro to reimburse Nalcor for those costs associated with Hydro's use of the assets. In this circumstance,

[3] Hydro's next GRA is expected to be in filed 2019 for rates to be approved in the second half of 2020.
[4] Nalcor's June 23, 2017 project update stated that average island residential electricity rates are expected to increase to 22.89 ¢ per kWh (plus HST) in 2021 primarily as a result of the Muskrat Falls Project. The present average rate for these customers is 11.7 ¢ per kWh (plus HST), a gap of 11.19 ¢ per kWh. The level of increase in customer rates resulting from the supply from the Muskrat Falls Project is a policy decision to be made by the Provincial Government.

Hydro will file an application to the Board seeking to place these costs in a separate cost deferral account for future recovery from customers.[5]

6.3. Off-Island Purchases Deferral Account

In general, cost variances between actual Island Interconnected System supply costs and those reflected in customer rates are deferred for future recovery though the Rate Stabilization Plan (RSP), the Energy Supply Cost Variance Account (ESCVA), and the Holyrood Conversion Rate Deferral Account. These accounts permit the deferral of supply cost variances that result from fuel cost variances (No. 6 fuel and gas turbine fuel), power purchase cost variances related to specific power purchase agreements, and earnings impacts that result from variances in wholesale and industrial energy sales from those reflected in the Test Year.

The existing supply cost deferral accounts will not capture savings that may result from off-island power purchases.[6] Under the current mechanics of Hydro's existing supply cost deferral accounts, savings related to off-island power purchases would result in increased earnings to Hydro. Therefore, Hydro is proposing an Off-Island Purchases Deferral Account to set aside the net savings for use in helping manage electricity rates for customers during the implementation of rates to recover the cost of the Muskrat Falls Project. The proposed Off-Island Purchases Deferral Account is provided in Schedule 6-I to this Supplemental Evidence.

The proposed Off-Island Purchases Deferral Account is reflected in Hydro's 2017 GRA filing in that Hydro's supply cost forecast, used in determining revenue requirements for the 2018 and 2019 Test Years, reflects the continued use of No. 6 fuel at Holyrood as if the Island remained

[5] While Order in Council OC2013-343 directs that costs associated with the Muskrat Falls Project be recovered from Island Interconnected rates, it prohibits the recovery of those costs until the project is commissioned or near commissioning and Hydro is receiving service.

[6] Supply cost variances as a result of variability in power purchases are dealt with through the ESCVA. However, the existing terms of the ESCVA identifies each source of purchase to be used in computing the cost deferral. Off-island power purchases are not included in the current ESCV Account definition. Therefore, the Holyrood No. 6 fuel savings from off-island power purchases will not flow to the ESCVA. Off-island power purchases will also impact the Holyrood fuel conversion rate and the balance to be recovered from customers.

isolated from the North American grid. The proposed deferral account includes any difference between costs attributable to off-island power purchases and the Test Year fuel-related costs that would have been incurred if that same amount of energy had been supplied from Holyrood.

Under Hydro's proposal, the fuel savings would be applied against the total cost of power purchases (including energy purchase costs and any delivery costs incurred to obtain off-island supply, including agency fees) and the operating and maintenance costs from Nalcor to access the LIL and LTA.

Upon conclusion of this GRA, the Board will determine whether the savings from off-island power purchases are: (i) used to minimize electricity rates during the Muskrat Falls Project pre-commissioning period; (ii) set aside for future use to help mitigate the impact of post-commissioning Muskrat Falls Project costs on customer rates; or (iii) some combination of providing rate mitigation during both the Muskrat Falls pre-commissioning period and the Muskrat Falls post-commissioning period.

The Board's decision as to the use of savings from off-island power purchases during the pre-commissioning period will not be known until the conclusion of the GRA. However, depending on the timing of the completion of the Maritime Link, Hydro could have access to the off-island power purchases in late 2017. Therefore, Hydro will be filing an application requesting interim approval to establish the proposed Off-Island Purchases Deferral Account to become effective December 1, 2017.[7] Direction as to the disposition of the deferral account balance will be subject to a further order of the Board at the conclusion of this GRA.

[7] Hydro anticipates filing this application in October 2017.

6.3.1. Cost of Off-Island Power Purchases

With the availability of the LIL and LTA prior to full commissioning of the Muskrat Falls Project, there is a significant opportunity to reduce Holyrood generation by using off-island power purchases in 2018, 2019, and 2020. For 2018 and 2019, the availability of off-island power purchases will primarily be from Recapture Energy.[8] In 2020, commissioning period energy[9] is anticipated to be available from the Muskrat Falls Plant.[10] In addition, Hydro will contract its affiliate company, Nalcor Energy Marketing, to solicit opportunities for energy from neighboring jurisdictions for import via the Maritime Link and the Labrador Island Link, supplementing available Recapture Energy and providing further savings.

In order to access off-island power purchases, Hydro will be required to enter into an agreement which will permit Hydro to use the LIL and the LTA and also require Hydro to pay the operating and maintenance costs for that use. Hydro is proposing that the operating and maintenance costs incurred to use the LIL and LTA be treated as a deferred regulatory expense to be charged to the proposed Off-Island Purchases Deferral Account. Hydro is also proposing that the deferral account include the cost of supply for Recapture Energy and the cost incurred to achieve power purchases from other jurisdictions.

6.3.2. Fuel Savings

Hydro's 2018 and 2019 Test Years reflects the continued use of No. 6 fuel at Holyrood as if the Island remained isolated from the North American grid. The proposed deferral account will be

[8] Under the terms of the Power Purchase Agreement between Hydro and Churchill Falls (Labrador) Corporation (CF(L)Co) (the NLH-CF(L)Co PPA), Hydro is able to, and does, purchase approximately 300 MW of Recapture Energy from CF(L)Co at a cost of 0.2¢ per kWh for use outside of the Province of Quebec. Hydro currently uses a portion of the Recapture Energy to supply its customers in Labrador with the remainder of the Recapture Energy sold to Nalcor Energy Marketing (NEM) at a cost of 0.2¢ per kWh for resale in external markets. Hydro does not profit from the arrangement with NEM, which is consistent with the long-standing treatment of Hydro's previous arrangement whereby external sales from Recapture Energy were segregated from regulated earnings and essentially treated as a direct dividend to the Province. Under the present arrangement, NEM provides a dividend to its shareholder, Nalcor energy, equal to any profit obtained from selling the excess Recapture Energy to market.

[9] Commissioning period energy refers to energy available from the Muskrat Falls Plan prior to near or full commissioning of the Muskrat Falls Project.

[10] Under the Muskrat Falls Power Purchase Agreement, Hydro has access to pre-commissioning energy from the Muskrat Falls Plant at no cost.

credited with the reduced Test Year No. 6 fuel costs that result from accessing off-island power purchases. There are two elements of the fuel cost savings proposed to be included in the new deferral account: (i) reduced Holyrood generation; and (ii) lower fuel inventory requirements than included in Hydro's Test Year forecasts.

In its GRA filing, Hydro is proposing the RSP operate in 2018 based on the 2015 Test Year and in 2019 based on the 2019 Test Year.[11] Therefore, for the operation of the proposed Off-Island Purchases Deferral Account, Hydro proposes the 2015 Test Year inputs be used to determine the fuel cost savings for 2018 and the 2019 Test Year inputs be used to determine the fuel cost savings for 2019.

Reduced Holyrood Generation

The generation savings are proposed to equal the Test Year fuel price multiplied by the number of barrels of No. 6 fuel that will be displaced as a result of the use of off-island power purchases. The number of barrels of fuel is proposed to be determined based on the off-island power purchases (kWh) divided by the Test Year Holyrood conversion rate.[12]

Hydro is proposing to compute the value of the fuel savings from reduced generation at Holyrood based on the Test Year fuel price. No. 6 fuel price variances currently flow through the RSP; therefore, the proposed approach avoids any duplication between the RSP and the proposed Off-Island Purchase Deferral Account.

The reduction in generation from Holyrood as a result of off-island power purchases will result in a reduction in the Holyrood fuel conversion rate from that which would otherwise be achieved. Hydro currently has a Holyrood Conversion Rate Deferral Account which defers the

[11] See correspondence to Board from Hydro dated August 23, 2017, in response to the Board's request for further information on the 2017 GRA filing dated August 14, 2017.
[12] The metered delivery point to determine the kWh of off-island power purchases over the LIL will be at Soldier's Pond and the metered delivery point for off-island power purchases over the Maritime Link will be at the Bottom Brook terminal station.

cost impacts of variances from the approved Test Year conversion rate in excess of $500,000. As such, Hydro is not proposing to include the cost impact of reduced Holyrood fuel conversion in the proposed deferral account.[13] This approach avoids any duplication between the Holyrood Conversion Rate Deferral Account and the proposed Off-Island Power Purchase Deferral Account.

Reduced Fuel Inventory

Hydro's 2018 and 2019 Test Year forecasts assume the continued use of No. 6 fuel at Holyrood reflecting the fuel inventory required as if the Island remained isolated from the North American grid. However, it is likely that after interconnection to the North American grid, providing the ability to access to off-island power purchases, Hydro may be able to reduce the amount of fuel inventory it must carry. As such, Hydro is proposing that the Off-Island Purchases Deferral Account capture the Test Year revenue requirement savings that result from the reduced volume of No. 6 fuel inventory relative to the Test Year No. fuel inventory reflected in the Test Year revenue requirement used to determine customer rates.

Financing Costs

Hydro is proposing that the balance in the proposed Off-Island Purchases Deferral Account accumulate interest based on the Test Year's approved weighted average cost of capital (WACC). This approach is consistent with the operation of the RSP. Therefore, for computing interest in the proposed deferral account, Hydro is proposing to use an interest rate for 2018 based on the approved 2015 Test Year WACC and an interest rate for 2019 and 2020 based on the approved 2019 Test Year WACC.

[13] The reduced Holyrood fuel conversion rate as a result of off-island power purchases will increase the likelihood that Hydro will incur the $500,000 cost reflected in the deadband of the Holyrood Conversion Rate Deferral Account.

6.4. Summary

Hydro is proposing that the Off-Island Purchases Deferral Account be established to set aside the net savings from off-island power purchases that will result from interconnection with the North American grid prior to the full commissioning of the Muskrat Falls Project. Hydro is also proposing that the net savings be set aside to help mitigate the impact of recovery of the Muskrat Falls Project costs on customer rates. Through evaluation of the evidence provided in the GRA process, the Board will determine whether Hydro's proposed approach to disposition is reasonable or if an alternate approach is preferred.

The proposed deferral account includes the difference between costs attributable to off-island power purchases and the Test Year fuel-related costs that would have been incurred if that same amount of energy had been supplied from Holyrood.

The existing supply cost deferral accounts will not capture savings that may result from off-island power purchases. Under the current mechanics of Hydro's existing supply cost deferral accounts, savings related to off-island power purchases would result in increased earnings to Hydro. Therefore, Hydro will be filing a related application to establish this deferral account on an interim basis effective December 1, 2017, with direction as to the disposition of the account to be determined by the Board at the conclusion of this GRA.

Approval to establish the proposed deferral account in advance of the engaging in off-island power purchases will provide for transparency and clarity on how the savings should be determined and recorded on Hydro's financial statements. Hydro will provide the Board with ongoing financial reporting on deferral account activity.

Chapter 6 – Schedule I

Proposed Off-Island Purchases Deferral Account

Newfoundland and Labrador Hydro
Off-Island Purchases Deferral Account

This account shall be charged or credited on a monthly basis by the amount of the Test Year supply cost variances on the Island Interconnected System that result from off-island power purchases prior to the full commissioning of the Muskrat Falls Project. The monthly transfers to the Off-Island Purchases Deferral Account will be determined as follows:

Fuel Consumption Savings + Fuel Inventory Savings - Cost of Off-Island Power Purchases

Fuel Consumption Savings shall be calculated as:

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

Where:

A = Off-Island Power Purchases at Point of Delivery (kWh);
B = Test Year Holyrood No. 6 Fuel Conversion Rate (kWh/barrel); and
C = Test Year Cost of No. 6 fuel ($ per barrel).

Fuel Inventory Savings shall be calculated annually as:

$$(D - E) \times C \times F$$

Where:

D = Test Year 13 month Average Volume of No. 6 Fuel Inventory in barrels;
E = Actual 13 month Average Volume of No. 6 Fuel Inventory in barrels;[1] and
F = Test Year Weighted Average Cost of Capital.

Cost of Off-Island Power Purchases shall be calculated as:

$$G + H$$

Where:

G = Cost of Off-Island Power Purchases including transmission tariffs and delivery costs; and
H = Amounts paid by Hydro for the use of Labrador Island Link and Labrador Transmission Assets.

Account Balance
The account balance will attract interest calculated monthly based on Hydro's approved Test Year weighted average cost of capital.

Disposition
Any balance in this account shall be disposed based upon future direction from the Board.

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[1] For the purpose of the calculation of fuel inventory savings, if the Actual 13 month Average Volume of No. 6 Fuel Inventory in barrels exceeds the Test Year 13 month Average Volume of No. 6 fuel inventory in barrels the difference will be assumed to be zero.

List of Abbreviations

List of Abbreviations

AMR	Automated Meter Reading
ARO	Asset Retirement Obligation
ASME	American Society of Mechanical Engineers
CBPP	Corner Brook Pulp and Paper Limited
CDM	Conservation and Demand Management
CEA	Canadian Electricity Association
CERP	Corporate Emergency Response Plan
CF(L)Co	Churchill Falls (Labrador) Co.
CIAC	Contributions in Aid of Construction
COGUA	Canadian Off-Grid Utilities Association
CSA	Canadian Standards Association
CSR	Customer Service Representatives
DAFOR	Derated Adjusted Forced Outage Rate
ECC	Energy Control Center
ERP	Enterprise Resource Planning
FERC	Federal Energy Regulatory Commission
FTE	Full Time Equivalent
Gensets	Generator Sets
GRA	General Rate Application
Holyrood	Holyrood Thermal Generating Station
HQ	Hydro Quebec
HVdc	High Voltage Direct Current
IEC	International Electrotechnical Commission
IEEE	Institute of Electrical and Electronics Engineers
IOC	Iron Ore Company of Canada
ISO	Independent System Operator
IVR	Interactive Voice Response
LIL	Labrador Island Link
LOLH	Loss of Load Hours
LTA	Labrador Transmission Assets

MCR	Maximum Continuous Rating
ML	Maritime Link
MW	Megawatts
MWh	Megawatt-hours
NARL	North Atlantic Refining Limited
NERC	North American Electric Reliability Corporation
NLSO	Newfoundland and Labrador System Operator
NPCC	Northeast Power Coordinating Council, Inc.
NUGS	Non-Utility Generators
OCI	Other Comprehensive Income
PPA	Power Purchase Agreement
RFI	Request for Information
ROE	Return on Equity
RORB	Return on Rate Base
RRA	Rural Rate Alteration
RSP	Rate Stabilization Plan
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SEM	System Equipment and Maintenance
T-SAIDI	Transmission System Average Interruption Duration Index
T-SAIFI	Transmission System Average Interruption Frequency Index
TY	Test Year
UFOP	Utilization Forced Outage Probability
WACC	Weighted Average Cost of Capital