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February 1, 2019

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 – Closing Submission

Enclosed, please find the original plus thirteen copies of Newfoundland and Labrador Hydro's Closing Submission in relation to the 2017 General Rate Application.

If you have any questions, please contact the undersigned.

Yours truly,

NEWFOUNDLAND AND LABRADOR HYDRO

Geoffrey P. Young, Q.C.
Corporate Secretary & General Counsel
GPY/sk

Encl.

cc: Gerard Hayes – Newfoundland Power
Paul Coxworthy – Stewart McKelvey
Denis J. Fleming – Cox & Palmer
Dennis Browne, Q.C., – Browne Fitzgerald Morgan & Avis
Dean Porter – Poole Althouse

ecc: Van Alexopoulos – Iron Ore Company
Senwung Luk – Olthuis Kleer Townshend LLP
Benoît Pepin – Rio Tinto

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*");

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

Newfoundland and Labrador Hydro

2017 General Rate Application
Closing Submission

February 1, 2019

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A. Background

On July 28, 2017, Newfoundland and Labrador Hydro's ("Hydro") 2017 General Rate Application ("GRA"), was filed with the Newfoundland and Labrador Board of Commissioners of Public Utilities (the "Board") pursuant to the *Public Utilities Act*, RSN, 1990, Chapter P-47 (the "*Act*"), requesting rates, among other proposals, for a two-year test period in 2018 and 2019. The general rates and revenue requirements proposed by Hydro reflect the utility's efforts to fulfill its mandate, which is to manage and control its costs while delivering safe, reliable service to its customers.

As reflected in the testimony of Mr. Jim Haynes, President of Hydro, there is a balance to be achieved in weighing reliability and least-cost considerations in fulfilling the company's mandate. Too great an emphasis on risk aversion can lead to increased costs, while assuming risk can decrease system reliability. Hydro's focus is in finding the right balance between the two.[1]

Hydro submits that its 2017 GRA proposals, as supported by the voluminous evidence filed with the Board, as well as the *viva voce* testimony of witnesses heard by the Board, reflect a cost of service that strike the appropriate balance proffered by Mr. Haynes. The purpose of these proposals 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 Hydro's 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. While many of Hydro's proposals, or components thereof, have been settled by agreement of Hydro and the GRA Intervenors (the "Parties") and are recommended for Board acceptance, it is the remaining unsettled proposals and components which are the primary focus of Hydro's final submission.

A.1. Procedural History

A.1.1. Timing of the General Rate Application Filing

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,

[1] Transcript, April 16, 2018, at pp. 54/24 to 55/11.

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.

Hydro filed its 2017 GRA on July 28, 2017. The 2017 GRA proposed, among other things, that Hydro's 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. Hydro proposed to establish a deferral account, the Off-Island Purchases Deferral Account, to include the difference between: (i) the actual costs attributed 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 ("Holyrood") based on the approved test years' unit cost of No. 6 fuel (Deferral Account Scenario). Hydro proposed that upon conclusion of the 2017 GRA, the Board would determine whether the savings from off-island power purchases would be: (i) used to minimize electricity rates during the Muskrat Falls Project pre-commissioning period, (ii) set aside for future use to help mitigate and smooth 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 Project pre-commissioning period and the Muskrat Falls Project post-commissioning period.

As the matter proceeded, Hydro materially revised its 2017 GRA to propose that the 2018 and 2019 Test Year revenue requirements and resulting rates reflect Hydro's projections for off-island purchases over the Labrador-Island Link ("LIL") and the Maritime Link (Expected Supply Scenario). In doing so, Hydro withdrew its previous proposal respecting the Deferral Account Scenario.[2]

A.1.2. Motions

A.1.2.1. Consumer Advocate's Motion for Information Regarding the Expected Supply Scenario

On January 4, 2018, the Consumer Advocate filed an application to delay the schedule for the 2017 GRA until Hydro filed certain additional information relating to the Expected Supply Scenario. On January 26, 2018, the Board issued Order No. P.U. 2(2018) directing Hydro to file additional information providing the 2018 and 2019 revenue requirements and cost of service studies based on the Expected Supply Scenario, setting out Hydro's assumptions and the support for those assumptions. The Board also requested that Hydro provide similar information based on Hydro's Deferral Account Scenario, using the fall 2017 fuel price update (Revised Deferral Account Scenario) and address the requirement for a

[2] In accordance with the "Supplemental Settlement Agreement," at p. 4, para. 14.

deferral account mechanism to address uncertainties related to supply cost variability for 2018 and 2019.

In compliance with the Board's direction, Hydro filed, on March 22, 2018, a report entitled "Summary Report - Additional Cost of Service Information." The report provided a summary of the cost of service, revenue deficiencies and customer rates impacts using both the Revised Deferral Account Scenario and the Expected Supply Scenario. The report also addressed the changes required in deferral mechanisms to deal with supply cost uncertainty in the 2018 and 2019 Test Years due to off-island purchases. The Expected Supply Scenario included in Hydro's 2018 and 2019 Test Year costs reflects Hydro's projections of off-island purchases over the LIL and the Maritime Link. Most of the savings over the Maritime Link were forecast to occur in the months prior to the LIL becoming available. Following the in-service of the LIL, Hydro proposed to use Recapture Energy to limit production at Holyrood. The forecast power purchase costs included the cost of Recapture Energy, the cost of imports over the Maritime Link and the forecast charges to Hydro for use of the LIL and the Labrador Transmission Assets ("LTA") for 2018 and 2019.

A.1.2.2. Hydro's Motion for Deferral of Cost of Service Methodology Issues

On April 4, 2018, Hydro filed an application for an order defining the scope of the Cost of Service Methodology issues to be addressed in the 2017 GRA. The application arose in the context of Cost of Service Methodology issues raised by the Consumer Advocate in the 2017 GRA, specifically the classification of the 230 kV transmission line from Bay d'Espoir to Western Avalon ("TL 267") between demand and energy, and the marginal cost signal to be reflected in Newfoundland Power's wholesale rate design as a result of the interconnection with the North American grid. It was Hydro's position that these issues should be deferred to the Cost of Service Methodology Review Hearing anticipated to be scheduled for later in 2018.

On July 16, 2018, Hydro and the Parties entered into the Supplemental Settlement Agreement"[3] which addressed, among other things, the Cost of Service methodology issues raised by the Consumer Advocate in the 2017 GRA. The conclusion of the Supplemental Settlement Agreement negated the need for a Board order respecting Hydro's Cost of Service Methodology motion.

[3] "Supplemental Settlement Agreement," filed on July 16, 2018.

A.1.2.3. Consumer Advocate's Motion Regarding Board Jurisdiction to Approve the Deferral Account Scenario and Related Filings

On April 5, 2018, the Consumer Advocate filed an application requesting an order of the Board declaring whether OC2013-342 and OC2013-343 collectively restrict the Board's jurisdiction to allow Hydro's 2017 GRA to recover any costs related to components of the Muskrat Falls Project. It was Hydro's position that the Board would not contravene OC2013-342 or OC2013-343 by approving the proposed Off-Island Purchases Deferral Account. The Board denied the Consumer Advocate's application, holding that a determination of the factual and legal issues raised in the application at that time would be premature. The Board stated that it expected the issues would be addressed further in the 2017 GRA proceeding.

On July 16, 2018, Hydro entered into the Supplemental Settlement Agreement, which proposed to establish customer rates based on the Expected Supply Scenario and, effectively, withdraws Hydro's previous proposal respecting the Deferral Account Scenario.

On July 20, 2018, Hydro filed "Supplemental Evidence - Customer Impacts Reflecting 2017 GRA Settlement Agreements," ("Supplemental Evidence") providing revenue requirement estimates reflecting the settlement agreements, recovery of the 2015 to 2017 deferred energy supply costs for the Island Interconnected System, and the estimated 2018 revenue deficiencies (or excess revenues) by class, among other items. Hydro subsequently clarified, in response to a request from the Board, that its revised proposal included 2019 rates which recover its 2019 revenue requirement reflecting the Expected Supply Scenario.[4] Hydro further clarified its proposal by filing, on August 2, 2018: (i) a revised Part B of its 2017 GRA, updated to reflect the settlement agreements and Supplemental Evidence; (ii) a revised Table 5-7 showing 2018 revenue deficiencies/excess revenues by customer class; and (iii) a revised Table 5-8 showing 2019 billing impacts by customer class.

On August 31, 2018, Hydro filed the "Interim Transmission Funding Agreements – Information Filing" regarding the Interim Transmission Funding Agreements entered into by Hydro for use of the LIL and the LTA prior to the assets' commissioning and/or substantial completion. Hydro explained that Nalcor had announced in June 2017 that the LIL and the LTA were expected to be available for service in mid-2018, however, delays resulted in a revised schedule for the transmission assets. At the time of the filing, dynamic commissioning (i.e., testing while energized) was ongoing and there remained an expectation

[4] The revenue requirement is shown in "Supplemental Evidence," Sch. 3.

that the assets would be available for service in early 2019. In order to gain access to the lower cost sources of energy, Hydro forecasted that it would incur and recover from its customers actual costs attributable to off-island power purchases, including transmission costs for delivery. These costs would include the operations and maintenance ("O&M") costs associated with the LIL and the LTA. To enable this, Hydro entered into agreements with the owners of the LIL and LTA to ensure the assets would be made available for service earlier than would otherwise be required for delivery of Muskrat Falls generation. Hydro further obtained a guarantee from Nalcor that the availability of the assets and overall island imports would be sufficient to ensure the savings realized by using off-island purchases would offset the costs incurred by Hydro for ensuring the assets' availability for service.

At this juncture, the issues raised by the Consumer Advocate's application of April 5, 2018 regarding whether OC2013-342 and OC2013-343 collectively restrict the Board's jurisdiction to allow Hydro to recover costs related to components of the Muskrat Falls Project (e.g., costs paid pursuant to the Interim Transmission Funding Agreements) remained to be argued upon close of the GRA hearing. However, on October 25, 2018, Government issued OC2018-213 directing the Board to, upon application from Hydro, adopt a policy that all costs incurred by Hydro for the use of the LIL and the LTA under the Interim Transmission Funding Agreements be placed into a deferral account with disposition of the deferral account to be addressed following a further application by Hydro.

On November 20, 2018, Hydro filed an application seeking approval to defer all costs incurred by Hydro for the use of the LIL and the LTA under the Interim Transmission Funding Agreements. The Board did not receive any comments in respect of the application from the Consumer Advocate or any of the other parties to the 2017 GRA. The Board approved Hydro's proposed deferral account on December 12, 2018.[5]

On November 14, 2018, Hydro filed a revised "2018 Cost Deferral and Interim Rates Application," accounting for the issuance of OC2018-213. As part of the revised application, Hydro provided an updated "Part B, Hydro Proposals" respecting the 2017 GRA. The update included a proposal regarding revenue requirement reflecting that the costs Hydro is required to pay for the use of the LIL and LTA during the period prior to full commissioning of the Muskrat Falls Project in accordance with the Interim

[5] Order No. P.U. 47(2018).

Transmission Funding Agreements be excluded from the calculation of Hydro's 2018 and 2019 Test Year revenue requirements.

In light of the foregoing developments, it is Hydro's position that the factual and legal issues raised in the Consumer Advocate's April 5, 2018 motion and deferred by Order No. P.U. 17(2018) are now moot and do not require any further treatment in this proceeding.

A.1.3. Interim Rate Applications

Over the course of the 2017 GRA proceedings, it became necessary for Hydro to make interim rate applications, in respect of different customer classes, to ensure Hydro would have the opportunity to earn a just and reasonable return during the 2018 fiscal year. The interim rate applications are summarized below.

On February 9, 2018, Hydro filed an application for approval of interim Island Industrial Customer rates and Labrador Industrial Transmission rates to be effective April 1, 2018. The Board partially granted the application by issuing Order No. P.U. 7(2018). The Board approved Hydro's proposed interim Island Industrial Customer rates, effective on all electrical consumption on and after April 1, 2018. The Board further approved the establishment of a deferral account to track for each Island Industrial Customer beginning on April 1, 2018, the difference between the approved specifically assigned charges and the amount that would be charged if the O&M methodology for specifically assigned charges proposed in the 2017 GRA is approved. The Board did not approve the proposed Labrador Industrial Transmission rates.

On April 13, 2018, Hydro filed an interim rates application for approval of proposed interim rates for Utility Customers effective July 1, 2018. On April 20, 2018, Hydro filed a revised application to correct the calculation of the 2018 revenue deficiency and recovery percentage. In Order No. P.U. 15(2018), issued on May 28, 2018, the Board approved, *inter alia*, on an interim basis, the proposed Utility Customer rates, effective on all electrical consumption on and after July 1, 2018.

On October 26, 2018, Hydro filed a "2018 Cost Deferral and Interim Rates Application." The application proposed, among other things, updated interim customer rates for Island Industrial Customers to be implemented in concert with the Rate Stabilization Plan ("RSP") rate update required for January 1,

2019. Subsequent to the filing of the application, Order in Council OC2018-213 necessitated that Hydro revise its application on November 14, 2018 to remove the proposal for the deferral of the O&M costs for the LIL and the LTA. By Order No. P.U. 48(2018), the Board approved on an interim basis the proposed revised Island Industrial Customer rates, to be effective upon the implementation of the revisions to the RSP adjustments for January 1, 2019. The Board further approved the 2018 Cost Deferral Account related to the differential in the 2018 depreciation expense associated with the proposed change in depreciation methodology.

A.1.4. Approval of Settlement Agreements

At multiple junctures during the 2017 GRA proceedings, Hydro and the Parties, with participation by Board Hearing Counsel, successfully negotiated settlement of issues related to, and components of, Hydro's proposals. As a result of those successful negotiations, there are three settlement agreements before the Board in this matter, the Settlement Agreement,[6] the Supplemental Settlement Agreement, and the Labrador Settlement Agreement.[7] Achieving these arrangements enabled Hydro, the Parties, and the Board to reduce the length of the hearing and to forego the *viva voce* testimony of several expert witnesses.

These agreements were reached after detailed and involved negotiations and constitute the common positions of the Parties on these issues. All Parties were represented by learned and competent counsel and advised by experts. Hydro wishes to note its appreciation to the Parties and to Board staff and external counsel for their assistance and cooperation on this matter. The settlement agreements are before the Board for its consideration.

Hydro joins the other Parties and Board counsel in recommending their acceptance.

B. Legislative Requirements

The following statutory provisions, directives, and related considerations, including Orders in Council, are relevant to the Board's assessment of Hydro's proposals.

[6] "Settlement Agreement," filed April 16, 2018.
[7] "Labrador Settlement Agreement," signed August 24, 2018.

B.1. Statutory Authority and Duties of the Board

Hydro's 2017 GRA seeks approval of rates under the Board's authority existing under Sections 70 and 71 of the *Act*.

In carrying out its duties under the *Act*, pursuant to Section 4 of the *Electrical Power Control Act, 1994, SNL 1994, Chapter E-5.1* (the "*EPCA*"), the Board is required to implement the power policy stated in sections of the *EPCA*.

In addition to the rate and rule setting powers of the Board that exist under Sections 70 and 71, the *Act* gives powers and guidance to the Board with respect to a number of determinations it has to make with regard to the rate setting process. These include the setting of rate base (Section 78), the setting of return on rate base (Section 80), and the determination and approval of a number of accounting matters (e.g., Sections 67, 68, and 69). Under Section 80 of the *Act*, a public utility is entitled to earn a just and reasonable return on its rate base which shall be in addition to the expenses that the Board may allow as reasonable and prudent and properly chargeable to operating account.

Both the *Act* and the *EPCA* (Section 4.1 of the *Act* and Section 5.2 of the *EPCA*) contain provisions whereby the Lieutenant Governor in Council is empowered to exempt certain activities of public utilities from the Board's jurisdiction. The *EPCA* contains provisions (found in Section 5.1) that empower the Lieutenant Governor in Council to give direction to the Board on power policy and rate setting matters.

B.2. Directions to the Board

Directions have been given to the Board under Section 5.1 of the *EPCA* with regard to a number of rates policy issues. Attached to Hydro's response to PUB-NLH-079 are 20 Orders in Council related to the proposed customer rates, other than rural rates, including:

- OC2003-406, which directs the Board with regard to recovery in rates of a utility's costs related to projects exempted by Order in Council;
- OC2009-063, which directs the Board with regard to Hydro's rate of return on equity ("ROE") and capital structure;
- OC2010-216 (as amended by OC2010-317), which directs the Board with regards to the RSP;

- OC2011-218, with regards to the Debt Guarantee Fee paid by Hydro;
- OC2013-089 (as amended by OC2013-207 and OC2014-319) and OC2013-090 (as amended by OC2013-208), which direct the Board with regard to Island Industrial rates and the RSP;
- OC2013-257, which directs the Board with regard to exemption of activities pertaining to Exploits Generation; and
- OC2013-343, which directs the Board with regard to recovery in rates of costs, expenditures and payments paid by Hydro under an agreement or arrangement to which OC2013-342 (the "Muskrat Falls Project Exemption Order") applies.

Also related to the proposed customer rates, other than rural rates, is the Muskrat Falls Project Exemption Order. The Order in Council directs that certain costs, expenditures and payments incurred by Hydro respecting the Muskrat Falls Project are exempt from the application of the *Act* and Part II of the *EPCA*.[8]

OC2018-213 is also related to the proposed rates, other than rural rates. OC2018-213 directs the Board on the deferral of costs, expenditures and payments incurred by Hydro for use of the LIL and the LTA prior to full commissioning of the Muskrat Falls Project. The Order in Council directs that upon an application by Hydro the Board adopt a policy that the costs incurred by Hydro under the Interim Transmission Funding Agreements be placed into a deferral account. The Order in Council further states that disposition of the deferral account is to be addressed by the Board following a further application by Hydro in that regard.

Attached to Hydro's response to PUB-NLH-084 are 18 Orders in Council that provide direction on setting rural rates, including:

- OC2003-347, OC2006-512, OC2008-365, OC2009-390, OC2010-322, OC2012-329, OC2014-372, OC2015-300, OC2016-104, OC2016-287, OC2017-121 and OC2017-193, which, in series, direct the Board with regard to rates charged to Non-Government Rural Isolated Domestic and General Service customers; and

[8] OC2013-342 is included as an attachment to "Hydro's Submissions," filed on April 30, 2018, in reply to the Consumer Advocate's motion requesting clarification of the jurisdiction of the Board.

- OC2007-304, which direct the Board with regards to an energy rebate for Rural Isolated Diesel and Labrador Straits/L'Anse-au-Loup Area Residential Customers.

The following Orders in Council merit additional discussion as they concern matters of particular relevance to the 2017 GRA.

B.2.1. OC2009-063 - Return on Equity

OC2009-063 directs the Board to set the same target ROE as most recently set for Newfoundland Power. The ROE is used in the determination of the setting of the return on rate base under Section 80 of the Act. The Lieutenant Governor in Council has directed that: (i) the Board approve Hydro's return on rate base, calculated using the rate of ROE last approved for Newfoundland Power in a general rate application or through Newfoundland Power's Automatic Adjustment formula, (ii) Hydro is to earn a ROE on its entire rate base including amounts related to rural assets, and (iii) Hydro is to be permitted to have the proportion of equity in its capital structure up to a maximum of the same approved for Newfoundland Power.

In Board Order No. P.U. 2(2019), the Board approved, for ratemaking purposes, a rate of ROE of 8.5% for Newfoundland Power and a common equity component in its capital structure not to exceed 45%.

Such being the case, Hydro submits that in accordance with OC2009-063 the rate of ROE to be used in the 2017 GRA for calculating Hydro's return on rate base is 8.5%.

Hydro proposed, in "2017 General Rate Application," Vol. II, Ex. 12, methodology to enable continuous compliance with OC2009-063 in the event of changes in the ROE between test years for Hydro that result from changes in the ROE for Newfoundland Power.

The Parties agreed to the methodology proposed as it relates to revenue requirement determination; other items proposed in the methodology were modified during settlement negotiations and are reflected in the Settlement Agreement.[9]

[9] "Settlement Agreement," at p.5, para. 24.

To give effect to the spirit and intent of this directive, care must be taken to ensure that Hydro's return is not eroded or encroached upon by offsetting the return with some other amount or component of Hydro's costs. OC2009-063 provides no authority to do so and none should be inferred.

B.2.2. OC2013-342, OC2013-343 and OC2018-213 – Muskrat Falls Project Costs and Interim Transmission Funding Agreement Costs

While OC2013-343 directs that costs associated with the generating and transmission components of the Muskrat Falls Project[10] are to be recovered from Island Interconnected rates, it prohibits the recovery of those costs until each such project component is commissioned or near commissioning and Hydro is receiving services. As the components of the Muskrat Falls Project have not yet reached this status, the recovery of the Muskrat Falls Project costs, which will be required under OC2013-343, has not been triggered.

On October 25, 2018, the Lieutenant Governor in Council issued OC2018-213 directing the Board to, upon application from Hydro, adopt a policy that all costs incurred by Hydro for the use of the LIL and the LTA under the Interim Transmission Funding Agreements be placed into a deferral account with disposition of the deferral account to be addressed following a further application by Hydro.

On November 20, 2018, Hydro filed an application seeking approval to defer all costs incurred by Hydro for the use of the LIL and the LTA under the Interim Transmission Funding Agreements. The Board approved Hydro's proposed deferral account on December 12, 2018.[11]

As part of Hydro's revised "2018 Cost Deferral and Interim Rates Application,"[12] Hydro filed, on November 14, 2018, an updated "Part B, Hydro Proposals" respecting the 2017 GRA. The updated proposals included, as an item of revenue requirement, that the costs Hydro is required to pay for the use of the LIL and LTA during the period prior to full commissioning of the Muskrat Falls Project in accordance with the Interim Transmission Funding Agreements be excluded from the calculation of Hydro's 2018 and 2019 Test Year revenue requirements.

[10] Being those costs described and exempted by OC2013-342.
[11] P.U. 47(2018).
[12] Hydro's "2018 Cost Deferral and Interim Rates Application" was originally filed on October 26, 2018, prior to Hydro receiving a copy of OC2018-213. The Application was revised on November 14, 2018, to account for, among other things, OC2018-213.

Hydro therefore does not seek to include in revenue requirement for recovery any Muskrat Falls Project related costs exempted by OC2013-342, nor any Interim Transmission Funding Agreements costs attributable to off-island purchases, in the 2017 GRA. The 2017 GRA accords with the directions of the Lieutenant Governor in Council given in OC2013-342, OC2013-343 and OC2018-213.

B.2.3. OC2003-347 – Subsidization of Rural Rates

OC2003-347 continues the longstanding policy of Government with respect to isolated rural rates. Notably, the policy directs the Board to set rates for Hydro's Isolated Customers such that "lifeline rates" are continued for domestic residential customers, and preferential rates are provided to fish plants and to churches and community halls. OC2003-347 also directs that the Rural Deficit be charged to Newfoundland Power and Hydro's Rural Labrador Interconnected Customers.

The rates proposed in the 2017 GRA for Rural Customers accord with such direction, as well as with the policies for Hydro Rural rates as approved in Order No. P.U. 14(2007).

B.3. Rate Mitigation

On September 5, 2018, the Lieutenant Governor in Council directed reference questions to the Board regarding rate impacts related to the Muskrat Falls Project and rate mitigation options (the "Rate Mitigation Reference"). The reference questions ask the Board to review and report on options to reduce the impact of Muskrat Falls Project costs on electricity rates up to the year 2030 or such shorter period as the Board sees fit. The options to be reviewed by the Board are to include cost savings and revenue opportunities with respect to electricity, including generation, transmission, distribution, sales, and marketing assets and activities of, among others, Hydro.

Hydro submits that for the purposes of regulatory efficiency, the Board should review in the Rate Mitigation Reference, and not in the 2017 GRA, those matters that have specifically been referred to it for review by the Lieutenant Governor in Council, where decisions on those issues are not required to make the essential determinations in the 2017 GRA. That being said, some of the matters that have been referred touch upon broad matters of Hydro's operational efficiency and effectiveness. These will overlap with some of the revenue requirement and other issues that, by necessity, arise in this and every GRA. The fact that those issues arise in the Rate Mitigation Reference cannot reduce or remove the Board's jurisdiction to decide the issues before it under the 2017 GRA.

B.4. Timing of 2017 General Rate Application Filing and use of 2018 and 2019 Test Years

Paragraph 3(a)(ii) of the *EPCA* reads as follows:

> 3. It is declared to be the policy of the province that
>
> (a) the rates to be charged, either generally or under specific contracts, for the supply of power within the province . . .
>
> (ii) should be established, wherever practicable, based on forecast costs for that supply of power for 1 or more years,

This provision provides ratemaking guidance to the Board and indicates that test years – "*wherever practicable*" – should be forecast test years. There are two circumstances where this requirement would not apply: (i) where the Board is specifically directed otherwise under Section 5.1 of the *EPCA,* and (ii) where the Board in applying proper ratemaking principles deems that, for some reason, the use of a forecast test year is not practicable.

There was no Government directive issued in the present matter as to the test year to be used.

In Order No. P.U. 49(2016), the Board ordered, among other things, that Hydro file the 2017 GRA no later than March 31, 2017, with a 2018 Test Year. On February 20, 2017, Hydro filed an application requesting approval to file the 2017 GRA on or before July 31, 2017, reflecting 2018 and 2019 Test Years. In Order No. P.U. 8(2017), the Board allowed such extension and stated that Hydro's proposal that the 2017 GRA be based on both a 2018 and 2019 Test Year could be filed as part of the 2017 GRA.

Hydro filed the 2017 GRA on July 28, 2017 in compliance with Order No. P.U. 8(2017). Following its filing, Hydro filed for interim relief with the Board as previously noted.

Although 2018 is now closed, this does not impair the relevancy or value of the test year information before the Board.

C. Issues and Argument

C.1. Issues Affecting Return

C.1.1. Settled Items

C.1.1.1. Automatic Adjustment of Hydro's Return on Equity

- The Parties agreed to the methodology proposed by Hydro, in "2017 General Rate Application," Vol. II, Ex. 12, for determining revenue requirement adjustments to flow-through by customer class as a result of changes in the ROE between Hydro test years that result from changes in the ROE for Newfoundland Power.[13]
- The Parties further agreed that the revenue adjustments to flow through to customer classes on the Island Interconnected System will be held in a deferral account until disposition through customer rates at the time of rate changes that result from the operation of the RSP.[14, 15]
- The Parties agreed that Hydro's excess earnings account definition will be revised to reflect the revised ROE to apply between test years.[16]
- The Parties agreed that the revenue requirement adjustments to flow through to customers on the Labrador Interconnected System will occur through rate changes at the same time as the implementation of the Hydro rural rate change reflecting the revised ROE for Newfoundland Power.[17]

C.1.1.2. Muskrat Falls to Happy Valley Interconnection Project

In relation to the Muskrat Falls to Happy Valley Interconnection Capital Project (the "MF-HVY Project"):

- The Parties agree to the exclusion of the MF-HVY Project from Hydro's rate base in the 2018 Test Year and in the calculation of depreciation expense for the 2018 Test Year;[18]

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[13] "Settlement Agreement," at p. 5, para. 24(i).
[14] "Settlement Agreement," at p. 5, para. 24(iv).
[15] Hydro filed information on the ROE Rate Change Deferral Account Definition on May 15, 2018.
[16] "Settlement Agreement," at p. 5, para. 24(ii).
[17] "Settlement Agreement," at p. 5, para. 24(iii).
[18] "Labrador Settlement Agreement," at p. 2, para. 7(a).

- The Parties agree to the inclusion of the MF-HVY Project in Hydro's closing rate base for the 2019 Test Year, if approved by the Board for construction to be completed in 2019 prior to Hydro fling its 2017 GRA Compliance Application;[19]
- The Parties agree that if, at the time of Hydro's 2017 GRA Compliance Application, the MF-HVY Project is not approved by the Board for construction to be completed in 2019, the Parties agree that the MF-HVY Project will be excluded from the 2019 Test Year rate base; and[20]
- The Parties agree to the exclusion of depreciation associated with the MF-HVY Project in the calculation of 2019 Test Year revenue requirement.[21]

The customer impact of the inclusion of the MF-HVY Project in rate base will not be known until the 2017 GRA Compliance Application, as the MF-HVY Project is currently before the Board in a separate proceeding.

C.1.1.3. Working Capital Methodology

The Parties agreed that Hydro shall continue to use the currently approved working capital methodology, as outlined in "2017 General Rate Application," Vol. II, Ex. 9, with the updated net lag days proposed in the Application.[22]

C.1.1.4. Average Rate Base Methodology

The Parties agreed that Hydro shall continue to use the currently approved methodology, as described in "2017 General Rate Application," Vol. II, Ex. 10, to determine rate base, including beginning-of-year and end-of-year averaging for capital assets in service. Hydro may apply to the Board for a different treatment of significant capital additions on a case-by-case basis.[23]

[19] "Labrador Settlement Agreement," at p. 2, para. 7(b).
[20] "Labrador Settlement Agreement," at p. 2, para. 7(c).
[21] "Labrador Settlement Agreement," at p. 2, para. 7(a).
[22] "Settlement Agreement," at p. 3, para. 14.
[23] "Settlement Agreement," at p. 3, para. 13.

C.1.1.5. Excess Earnings Definition

The Parties agreed that the definition of the Excess Earnings Account proposed in "2017 General Rate Application," Vol. I, Ch. 4, Sec. 4.6.3 should be approved.[24] This definition includes the allowable range of return on rate base of +/- 20 basis points as approved in Board Order No. P.U. 49(2016).[25]

C.1.2. Unresolved Items

C.1.2.1. Rate Base

Hydro's rate base is comprised of its investment in capital assets in use, deferred costs, fuel inventory, materials and supplies inventory, and cash working capital allowances.

C.1.2.1.1. <u>Capital Assets included in Rate Base</u>

Hydro's average capital assets included in rate base have increased materially from the 2015 Test Year as a result of substantial capital investment in electrical infrastructure on the island and Labrador systems. The increase is primarily due to capital additions for the period from 2016 to the 2018 Test Year, largely as a result of the addition of a 230 kV transmission line from Bay d'Espoir to Western Avalon ($291.7 million). [26] Since the beginning of the 2017 GRA proceeding, the forecast of capital assets to be included in Hydro's 2018 and 2019 Test Year Average Rate Base has changed.

As noted by Ms. Hutchens in her testimony, Hydro intends to reflect an updated forecast of capital assets to be included in its 2018 and 2019 Test Year Average Rate Base when it provides the revised revenue requirement and average rate base for the 2018 and 2019 Test Years in its 2017 GRA Compliance Application.[27] Specifically, Hydro proposes to update the 2018 Test Year for the 2018 Capital Expenditures as outlined in the 2018 Capital Expenditures and Carryover Report.[28] In addition, Hydro proposes to update the 2019 Test Year capital expenditures based upon the updated 2019 forecast.[29]

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[24] "Settlement Agreement," at p. 4, para. 23.
[25] P.U. 49(2016), at p. 137, para. 10.
[26] "2017 General Rate Application," Vol. I, Ch. 4, at pp. 4.8 to 4.9.
[27] Transcript, July 25, 2018, at pp. 90-93.
[28] To be filed with the Board on March 1, 2019.
[29] For all capital expenditures except the MF-HVY Project, the updated 2019 capital expenditure forecast is comprised of the approved 2019 capital budget application as per Board Order P.U. 35 (2018), supplemental capital relating to Board Order P.U. 38 (2018) and the Allowance for Unforeseen Rigolet Diesel Engine Failure, and the updated 2019 carryovers as outlined in the 2018 Capital Expenditures and Carryover Report. The 2019 forecast would also be updated for the MF-HVY Project as agreed in the Labrador Settlement Agreement.

C.1.2.1.2. <u>Inclusion of Deferred Costs</u>

Hydro submits that the deferred amount for estimated revenue shortfalls is properly included in rate base and is consistent with decisions of the Board in previous proceedings.

Hydro's rate base includes estimated revenue shortfalls related to delayed implementation of interim and final rates resulting from the 2017 GRA.[30] In his pre-filed testimony, Mr. P. Bowman proposed that Hydro's revenue shortfall should be financed using short-term debt, thus ensuring Hydro does not receive a return equal to Hydro's Weighted Average Cost of Capital by including the deferral in rate base.[31] Hydro submits that the deferred amount is properly included in rate base and is consistent with decisions of the Board in previous proceedings.[32]

Upon receiving the Board's final 2017 GRA order, Hydro proposes to include deferred balances such as the approximately $65.4 million related to 2015, 2016, and 2017 Supply Cost Deferrals[33] and its forecast 2018 and 2019 Test Year revenue deficiencies in its calculation of rate base for the 2018 and 2019 Test Years, as appropriate, which will be provided in the 2017 GRA Compliance Application.

C.1.2.1.3. <u>Basis for Fuel Inventory and Foreign Exchange on Fuel</u>

Hydro proposes that the RSP Rules be clarified in the 2017 GRA Compliance Application to state that fuel converted to Canadian dollars includes foreign exchange losses and gains.

Hydro proposes to update the No. 6 fuel price used in calculating its 2019 Test Year fuel inventory to reflect the most current fuel rider forecast available at the time of the 2017 GRA Compliance Application filing and with the Supplemental Settlement Agreement.[34,35] This is consistent with the approach used in the 2013 GRA Compliance Application filing. Hydro proposes to compute the 2018 fuel inventory based on the 2015 Test Year fuel price, consistent with what Hydro has proposed for the 2018 Test Year revenue requirement.

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[30] "2017 General Rate Application," Vol. I, Ch. 4, at pp. 4.11 to 4.12.
[31] Pre-filed Testimony of Patrick Bowman, at pp. 29 to 31.
[32] Board Order No. P.U. 14(2017), at pp. 10 to 13.
[33] "2015 to 2017 Supply Cost Deferral Evidence," Rev. 2, at p. 29.
[34] Hydro's response to NP-NLH-346 notes that fuel inventory costs provided in the "2018 Cost Deferral and Interim Rates Application," App. D, are based on the report filed on March 22, 2018 entitled "Summary Report - Additional Cost of Service Information." It also notes that Hydro intends to update its fuel inventory cost calculation in its 2017 GRA Compliance Application based on the most current fuel forecast.
[35] "Supplemental Settlement Agreement," at p. 4, para. 19.

Hydro purchases a significant amount of No. 6 fuel in US dollars. Hydro notes that the RSP allows deferral of fuel costs resulting from fuel price variances, including foreign exchange fluctuations. Prior to the implementation of International Financial Reporting Standards, Hydro recorded the full amount of the foreign exchange gain or loss in inventory. Upon adoption of International Financial Reporting Standards, Hydro segregated the foreign exchange gain or loss which would require immediate charge to net income instead of inventory. In order to keep accounting for the RSP consistent with prior years, Hydro created a regulatory asset/liability to segregate the foreign exchange gain or loss until the fuel is consumed at which time the fuel inventory used and the relevant deferred foreign exchange on inventory would be realized and flow through the RSP.

As noted by Grant Thornton in their Financial Consultants Report:[36]

> It is not clear from the RSP rules if foreign exchange gains or loss should be reflected in inventory when converted to Canadian dollars from US dollars purchases. If the Board wanted to continue with the past practice to allow Hydro to flow foreign exchange losses and gains through the RSP upon consumption of fuel, we recommend that RSP rules be clarified to state that fuel converted to Canadian dollars includes foreign exchange losses and gains.

In order to address the issue raised by Grant Thornton, Hydro proposes that the RSP rules are clarified in the 2017 GRA Compliance Application to state that fuel cost in Canadian dollars includes foreign exchange losses and gains. This change will permit the operation of the RSP consistent with past practice and ensure the RSP continues its intended purpose, to smooth the impacts of fuel price variations.

C.1.2.2. Rate of Return on Rate Base

During the course of the 2017 GRA proceeding, Hydro's cost of debt has decreased. Based on the updated forecast cost of debt, Hydro projects that its revised 2018 Test Year rate of return on rate base would decrease from the 5.73%[37] as originally included in the 2017 GRA to approximately 5.45%.[38] Hydro proposes to update the 2018 and 2019 Test Year cost of debt in the 2017 GRA Compliance Application for Hydro's actual long term debt issuances in 2017 and 2018.[39] Hydro submits that updating

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[36] "Financial Consultants Report – Newfoundland and Labrador Hydro – 2017 General Rate Application," Grant Thornton, December 4, 2017, at p. 96/2-6.

[37] "2017 General Rate Application," Vol. I, Ch. 4, at p. 4.12.

[38] "2018 Cost Deferral and Interim Rates Application," Sch. 2, at pp. 2 to 3.

[39] In addition, Hydro will update its promissory notes for changes in planned borrowing.

its rate of return on rate base and average rate base calculations in its 2017 GRA Compliance Application is appropriate given the above noted changes.

C.2. Revenue Requirement

C.2.1. Settled Items

C.2.1.1. Hearing Costs

The Parties agreed that Hydro's proposals to recover the 2017 GRA hearing costs of $1.2 million and the Cost of Service and Rate Design Methodology Review Hearing costs of $0.5 million in customer rates evenly over three years are reasonable. These costs include external consulting costs of the Board and non-utility intervenors. The amortization will commence with the 2018 Test Year with the amounts to be determined by the Board.[40] The amortization of hearing costs as proposed is consistent with past practice as per Order No. P.U. 49(2016), at p. 64, para. 12.2.[41]

C.2.1.2. Vacancy Allowance

The Parties agreed that the number of vacancies in Full-Time Equivalent ("FTE") positions to be used in the calculation of operating labour costs in the Test Years will be 55, not 40 as proposed in the Application.[42]

C.2.1.3. Business Systems Transformation Program

The Parties agree that all costs and expenses related to the Business Systems Transformation Program described in the "2017 General Rate Application," Vol. l. Ch. 3, Sec. 3.7.2, at p. 3.38, Table 3-20, which were forecast to be $2.54 million in 2018 and $3.04 million in 2019, shall be removed from the revenue requirements in the Test Years and set aside in a deferral account. The Board is conducting a separate proceeding to evaluate the prudence of these costs.[43]

[40] "Settlement Agreement," at p. 4, para. 22.
[41] P.U. 49(2016), at p. 64.
[42] "Settlement Agreement," at p. 2, para. 10.
[43] "Settlement Agreement," at p. 3, para. 4.

C.2.1.4. Depreciation Methodology

The Parties agreed to the following aspects of Hydro's proposed modifications to the depreciation methodology, as referenced in "2017 General Rate Application," Vol. I, Ch. 4, Sec. 4.6.1 as well as Vol. III, Ex. 16:[44,45]

- To calculate depreciation expense in the 2018 and 2019 Test Years, Hydro will use the Average Service Life Group methodology applied on a deemed cost basis for assets put into service in 2015 and earlier, and on a whole life basis for assets put in service after 2015.
- The proposed updated estimates of service lives of assets included in the Application, including the revised truncation date for the Holyrood Plant, are appropriate and should be used in the calculation of depreciation expense in the 2018 and 2019 Test Years.
- Net salvage costs and asset removal costs for assets where assets are not replaced in the same location should be included in depreciation rates. For the calculation of the appropriate asset removal costs to be included in depreciation rates, the units of property listed in the "Settlement Agreement," Sch. A should not be included, and the removal costs to be included in depreciation expense associated with the units of property listed in the "Settlement Agreement," Sch. B should be at the rate of - 5%.
- Gains/losses on retirements will be recovered through accumulated amortization and no longer expensed.

C.2.1.5. Holyrood Inventory Allowance

Hydro agreed to withdraw its proposal, as per "2017 General Rate Application," Vol. I, Ch. 4, Sec. 4.2.3, to record an inventory allowance associated with the Holyrood Plant of $2.1 million in each Test Year.[46]

C.2.1.6. Asset Retirement Obligation

The Parties agreed to Hydro's proposed accounting treatment and calculation of Asset Retirement Obligations in the Test Years, as proposed in "2017 General Rate Application," Vol. I, Ch. 4, Sec. 4.2.3, at pp. 4.6 to 4.7.[47]

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[44] "Settlement Agreement," at p. 2, para. 9.
[45] The issue of the allocation costs related to the disposal of the Corner Brook Frequency Converter remains outstanding.
[46] "Settlement Agreement," at p. 4, para. 21.
[47] "Settlement Agreement," at p. 2, para. 8.

C.2.1.7. Capacity Assistance Agreements

Hydro believes its proposed recovery of the revised capacity assistance costs in the 2019 Test Year is reasonable and consistent with the intent of the Supplemental Settlement Agreement.

In the Supplemental Settlement Agreement, the Parties agreed that in its 2017 GRA Compliance Application, Hydro would *"…reduce its 2019 Test Year revenue requirement to reflect the capacity assistance agreements to be in effect for the 2018/2019 Winter Season."*[48] At the time the Supplemental Settlement Agreement was signed, Hydro was not planning to renew its capacity assistance agreements with Vale and Praxair and, as a result, the anticipated adjustment to 2019 capacity assistance costs would have provided a decrease in revenue requirement for 2019. However, with the uncertainty of available supply over the LIL for the 2018/2019 winter season, Hydro renewed its agreements with Vale and entered into an agreement for increased capacity assistance from Corner Brook Pulp and Paper.[49]

Hydro submits that the intention of the "Supplemental Settlement Agreement," at p. 5, para. 22 was to revise capacity assistance costs for 2019 *"to reflect the capacity assistance agreements to be in effect for the 2018/2019 Winter Season."*[50]

Hydro submits that the costs related to its capacity assistance arrangements are prudently incurred. The capacity assistance agreements are an important, cost-effective mechanism to minimize disruptions to customers in the event of a contingency or to maintain sufficient level of operating reserves for reliable operation of the electrical system.[51] Therefore, Hydro believes its proposed recovery of the revised capacity assistance costs in the 2019 Test Year is reasonable and consistent with the intent of the "Supplemental Settlement Agreement," at p. 5, para. 22.[52]

The Capacity Assistance Agreements are an important, cost-effective mechanism to minimize disruptions to customers in the event of a contingency or to maintain sufficient level of operating reserves for reliable operation of the electrical system.[53] Therefore, Hydro believes its proposed

[48] "Supplemental Settlement Agreement," at p. 5, para. 22.
[49] PUB-NLH-178.
[50] PUB-NLH-178.
[51] CA-NLH-328.
[52] PUB-NLH-178.
[53] CA-NLH-328.

recovery of the revised capacity assistance costs in the 2019 Test Year is reasonable and consistent with the intent of the "Supplemental Settlement Agreement," at p.5, para. 22. [54]

C.2.1.8. Employee Future Benefits

The Parties agreed to Hydro's proposed accounting treatment and methodology for calculation of Employee Future Benefits in the 2018 and 2019 Test Years, as referenced in "2017 General Rate Application," Vol. I, Ch. 3, Sec. 3.7.[55]

C.2.1.9. Supply Cost/Power Purchases

The Parties agree that the Cost of Service Methodology in the Expected Supply Scenario should be used to determine supply costs on the Island Interconnected System for the 2018 and 2019 Test Years[56] and that the Holyrood conversion rate for the 2019 test year used in setting customer rates is 583 kWh per barrel.[57] However, the Parties confirmed that the appropriateness of all costs proposed in the Expected Supply Scenario (other than those settled through the Settlement Agreement) remain unresolved.[58]

The Parties agree that the 2019 Test Year cost of No. 6 fuel to be used in Hydro's 2017 GRA Compliance Application shall be set based on the most current fuel rider forecast.[59]

C.2.2. Debt Guarantee Fee

C.2.2.1. Settled Issues

The Settlement Agreement, at p. 3, para. 12(a), contains the following:

> (a) Hydro shall reduce the amounts included in the Test Years related to the debt guarantee fee paid to the Government of Newfoundland and Labrador to:
>
> i) adjust the fee on long-term debt issues to be consistent with the recovery of such fee approved in Hydro's 2013 Amended General Rate application proceeding which results in a reduction of $567,000 in the 2018 Test Year and $672,000 in the 2019 Test Year revenue requirements; and

[54] PUB-NLH-178.
[55] "Settlement Agreement," at p. 2, para. 7.
[56] "Supplemental Settlement Agreement," at p. 4, para. 15.
[57] "Supplemental Settlement Agreement," at p. 4, para. 16.
[58] "Supplemental Settlement Agreement," at p. 4, para. 17.
[59] "Supplemental Settlement Agreement," at p. 4, para. 19.

ii) reduce interest costs to reflect savings of $515,000 in the 2018 Test Year and $529,000 in the 2019 Test Year associated with Hydro borrowing from the Government and not in the capital markets as forecast in the Application.[60]

C.2.2.2. Unresolved Items

The guarantee, and the on-lending, of Hydro's debt from the Province provide benefits to Hydro's customers. The recovery of the Debt Guarantee Fee remains a reasonable cost to be recovered through rates.

C.2.2.2.1. <u>History and Regulatory Treatment</u>

In Hydro's response to CA-NLH-131 some of the history of the debt guarantee was provided.

> The debt guarantee fee rate charged from 2001 to 2007 was 1% of Hydro's net debt outstanding. From 2008 to 2010 Government waived Hydro's requirement to pay the debt guarantee fee. The fee was reinstated in 2011, via an Order in Council, which directed Hydro to pay a guarantee fee of 25 basis points annually on the total guaranteed debt (net of sinking funds) with a remaining term to maturity of less than 10 years and 50 basis points annually on total guaranteed debt (net of sinking funds) with a remaining term to maturity greater than 10 years for debt outstanding as of December 31, 2010. For guaranteed debt issued subsequent to December 31, 2010, Hydro pays 25 basis points annually on the total guaranteed debt (net of sinking funds) with an original term to maturity of less than 10 years and 50 basis points annually on total guaranteed debt (net of sinking funds) with an original term to maturity greater than 10 years.

The Debt Guarantee Fee is paid to the provincial government by Hydro and is included in Hydro's costs under "Interest" in "2017 General Rate Application," Vol I, Ch. 4, Sch. 4-II, at p. 1/16.[61] Hydro has been paying guarantee fee amounts on its guaranteed debt under legislation and Orders in Council since 1990. Undertaking U#78 sets out the amount determined by the Province to be payable under the debt guarantee fee and indicates that it is payable for the recent on-lend of $700 million of debt from the Province.

In Order No. P.U. 49(2016) at p. 56, para. 11.7.1, ff., the Board Order resulted in 50% of the Debt Guarantee Fee forecast for the 2018 and 2019 Test Years being excluded from the calculated embedded

[60] "Settlement Agreement," at p. 3, para. 12.
[61] Refer to Hydro's response to IC-NLH-139, Attachment 1, for a calculation of the debt guarantee fee as well as the portion of those fees included in Hydro's revenue requirement.

cost of debt.[62] In finding that a payment of the Debt Guarantee Fee was appropriate and reasonable, the Board stated, at pp. 58 to 59:

> The Board has in the past accepted the essential role that the Government guarantee plays in Hydro's ability to maintain a sound credit rating in the financial markets of the world and to borrow at reasonable rates. While Hydro's debt ratio has recently improved somewhat it does not approach the level normally associated with stand-alone status. The evidence shows that Hydro's DBRS long-term debt rating of "A" continues to be a flow through of the rating of the province. In the circumstances the Board continues to believe that the Government guarantee plays a key role in supporting Hydro's ability to maintain a sound credit rating and access to capital at reasonable rates. The Board is satisfied that the guarantee serves to support least cost reliable service by increasing access to and flexibility in financing of Hydro's operating and capital requirements at reasonable rates. The Board finds that the Government guarantee provides a benefit to ratepayers and therefore it is appropriate to include an amount in the 2015 test year revenue requirement which reflects the reasonable costs and benefits associated with the guarantee.

Through the 2017 GRA Hearing Proceedings it was raised that there was difference between the circumstances that applied in the last hearing to the present. In particular, the recently incurred debt to which Hydro has proposed that the guarantee fee would be applied is not debt raised directly by Hydro from the market and guaranteed by the Province but is instead debt raised by the Province and on-lent to Hydro.[63] In response to a question on the matter, Ms. Hutchens replied:

> But what I will say though is the fee from the province stems directly—whether you call it a guarantee fee or another name to it. It stems from the fact that we are borrowing using the province's credit rating. And that is the sort of, underlying tenant of a debt guarantee fee. And because we are borrowing from a province, sorry because we are using the province's credit, that's what the debt guarantee fee attaches to. You know, I believe that the Board in the previous hearing did accept the value of the debt guarantee fee.[64]

The form of the borrowing is not the essential nature of the value passing under the Debt Guarantee Fee; the value stems from the Province making its credit rating and borrowing ability available to Hydro, thus providing the opportunity for lower borrowing costs to Hydro and, therefore, its customers. The

[62] The 50% exclusion is shown in the "2017 General Rate Application," Vol. I, Ch. 4, Sch. 4-IV, at p. 1/34, labeled "Less Interest Cost of Service Exclusions." Refer to Hydro's response to IC-NLH-139, Attachment 1 for detailed calculations.
[63] Transcript, July 25, 2018, at pp. 131 ff.
[64] Transcript, July 25, 2018, at p. 133/5-17.

obligation to pay the fee has not changed since the last hearing. It was acknowledged by the Board that the fee was to be included in revenue requirement not because the benefit derived was in accordance with a reasonable application of regulatory principles:

> The intervenors argued that the legislation no longer requires the payment of a fee and, in the absence of this requirement, the Board should not approve the inclusion of a guarantee fee in the revenue requirement. While the change in the legislative provisions may remove the legislative requirement for the payment of the fee, the Board must still consider whether the proposed guarantee fee is a reasonable cost which should be included in the revenue requirement to be recovered from customers.[65]

In Hydro's response to CA-NLH-131, it was shown that debt guarantee fees of up to 1% are commonplace among Canada's regulated utilities with two Crown utilities paying a fee of 1% and another paying a fee of 0.65% on their government guaranteed debt.

It is submitted that the inclusion of a Debt Guarantee Fee in revenue requirement of an amount as determined by the method set out in the Settlement Agreement remains reasonable and should be approved.

C.2.3. Unresolved Items

C.2.3.1. Operations and Maintenance Costs

Hydro's forecast O&M costs reflect the requirements to efficiently and effectively run the business. They are properly budgeted and comprise only those expenses necessary to ensure reliable service. Hydro submits its O&M costs are prudent and meet with its least-cost mandate. Details regarding some key areas of Hydro's operations are discussed in further detail below.

C.2.3.1.1. Organizational Cost Management

Overview

Hydro has addressed the concerns of the Board regarding the development of effective efficiency initiatives and practices through changes in management structure, redesign of short-term incentives, and focused efforts on efficiencies including the creation of a dedicated innovation and productivity team and improved cost management and budgeting.

[65] Order No. P.U. 49(2016), at p. 58.

In Board Order No. 49(2016), the Board recounted the arguments of Hydro and the Parties with respect to Hydro's productivity and cost control efforts and as to whether a productivity allowance was warranted.

The Board noted the following observations made by the Parties:[66]

- Hydro's management structure was not conducive to achieving efficiency gains;
- The Short-Term Incentives Program put little emphasis on cost control;
- Hydro had not sought outside assistance in identifying more efficient work execution practices;
- There was not a focused and directed effort to identify efficiencies;
- Hydro had not initiated an adequate number of efficiency initiatives; and,
- Hydro did not have specific programs directed towards efficiency.

The Board considered Hydro's budget process and other evidence with regard to efficiency and productivity management and determined that it evinced a lack of specific measures in relation to productivity.

The Board did not order a productivity allowance but it stated:

> The Board has made significant disallowances with respect to the proposed 2015 test year revenue requirement related to a number of specific costs, including salaries and benefits, professional services and travel expenses. The Board is satisfied that, given these disallowances and the timing of Hydro's next general rate application, a productivity allowance is not necessary or appropriate in the circumstances. However, the Board expects Hydro to implement improved processes in relation to identifying, establishing and documenting efficiency measures before the filing of its next general rate application. In the absence of such evidence the Board may consider further disallowances as well as a productivity allowance.[67]

Hydro submits that the evidence before the Board in the 2017 GRA differs greatly from that in the last GRA and that the foregoing observations made by the Board in the last GRA no longer apply.

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[66] Order No. P.U. 49(2016), at pp. 51 to 53.
[67] Order No. P.U. 49(2016), at p. 53.

To best understand Hydro's present view and activities with respect to its operations and its approach to productivity and cost control, a reference to Hydro's recent history is instructive. This has been discussed in evidence in the present matter.

In 2015, Hydro was driving its resources and forces hard to correct the circumstances which had led to the outages of the winter of 2014.[68] In the following year, 2016, due in part to a directive from the Government of Newfoundland and Labrador to government departments, crown corporations, and agencies to reduce costs, Hydro cut back significantly on expenditures in a number of areas and the result was a significant decrease in operating expenditures in that year. For example, internal directives were made to:[69]

- Review all service agreements and contracts to reduce costs (e.g., professional services and contract labour, including vegetation management);
- Conduct mandatory training only;
- Eliminate all conferences and related travel, including that related to training;
- Reduce travel as much as possible and conduct travel that is operationally critical only; and
- Reduce costs in all other areas where possible.

The outcome of this aggressive series of cost-cutting initiatives was a reduction of 2016 operating expenses from an originally budgeted amount of \$139.6 to \$123.9.[70] The obvious question that arises is – if Hydro was able to reduce costs to that degree and in that manner in 2016, is that level of expenditure sustainable? Hydro's answer was clearly established in the evidence – while these levels of expenditure might appear to be least-cost in the short-term, they are not sustainable over the longer term without exposing customers to an unacceptable risk of poor reliability and service. Therefore, it is irresponsible to attempt to operate at the 2016 levels of expenditures for more than a temporary period.

[68] Transcript, April 16, 2018, at pp. 74/24 to 75/24.
[69] PUB-NLH-054.
[70] PUB-NLH-054.

As arbitrary, across-the-board cuts and decreases to expenditures are not sustainable or prudent, an appropriate course of action to ensure least-cost, reliable service has to be identified. Through its evidence, Hydro has identified a multi-faceted approach – effect the necessary organizational change to ensure that the appropriate emphasis and management is placed on the right efforts and commence a systematic process of sustainable, enduring operational changes to achieve reliable, cost-efficient service.

Organizational Structure and Labour Cost

Hydro's new organizational structure is designed to ensure greater independence and focus on operations management, financial management, and performance accountability and to provide enhanced regulatory transparency.

Hydro's organizational structure has changed considerably since Hydro's last GRA. The changes were led by Mr. Haynes following his appointment as President in June 2016. Mr. Haynes created an organizational model and executive structure required to operate Hydro as an independent, standalone regulated utility. It marks a distinct change from the matrix model used by Hydro and Nalcor from the mid-2000s and provides for a renewed focus on Hydro's customers and essential business functions.[71] The new Hydro organizational structure was approved by Hydro's Board of Directors in August 2016 and the transition to the new structure continued into 2017.

The structure for the separate and dedicated executive team was informed by: (i) recommendations of the Board's external consultant, The Liberty Consulting Group ("Liberty");[72] (ii) a review of Hydro's pre-2007 structure; and (iii) a review of the structure of other regulated utilities across Canada, including Newfoundland Power Inc.[73] Hydro observed that in 2016 the Board expressed its concerns regarding aspects of regulatory transparency with Hydro operating as part of a matrix model:

> Since the last general rate application Hydro has undergone significant structural changes which, in the Board's view, makes it difficult to evaluate directly whether the

[71] Transcript, April 16, 2018, at pp. 47/17 to 54/12.

[72] "Supply Issues and Power Outages Review – Island Interconnected System – Executive Summary of Report on Island Interconnected System to Interconnection with Muskrat falls addressing Newfoundland and Labrador Hydro," The Liberty Consulting Group, December 17, 2014.

[73] Please refer to Hydro's response to PUB-NLH-024, at p. 1, fn. 2 - Other utilities *"including Nova Scotia Power, New Brunswick Power, Manitoba Hydro, Ontario Power Generation, Epcor, and BC Hydro."*

> resulting cost structure using shared services is least-cost compared to Hydro's operation as a stand-alone utility. . . .
>
> In the Board's view much of the concern in this proceeding surrounding intercompany charges related to issues of transparency associated with the level and recovery of these charges. The Board finds these concerns to be justified based on the evidence provided in this proceeding. The evidence does not demonstrate systematic time reporting by Hydro's executives. One of the factors cited by Hydro in the consideration of whether there is subsidization of the unregulated operations was systematic time reporting. The Board believes that a more detailed accounting of the intercompany activity between regulated and unregulated operations as part of Hydro's ongoing reporting to the Board will be beneficial to all stakeholders.[74]

The organizational changes were designed to ensure organizational independence for Hydro related to operations management, financial management, performance accountability, regulatory activities, and control and accountability for shared services. The new organizational structure enhances organizational effectiveness with a structure appropriate for Hydro's business environment and objectives for the near-term period and reduces the reliance on Nalcor for services that were previously shared among the Nalcor lines of business. Also, through the creation of the functionally separate Newfoundland and Labrador System Operator, it enables compliance with requirements arising with the interconnection to the North American grid.

With an increased emphasis on independence of operations and management, there were associated adjustments of various positions in an effort to place appropriate focus on specific areas of the business, while not incurring unnecessary increases in the overall FTE compliment.[75] Hydro has committed to not increasing FTEs in 2018-2019;[76] this includes the absorption of five Energy Control Centre Operators.[77]

There remains a select set of services which are provided through shared services offerings between Nalcor and Hydro as such an approach provides economies of scale; these include human resources, safety, and information systems.[78,79] These services are provided in accordance with Hydro's

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[74] Order No. P.U. 49(2016), at pp. 37 to 38.
[75] PUB-NLH-059, at p. 1/7-8 and Table 1. The net cost increase forecast resulting from the organizational change from 2015TY to 2019TY is $2.3 million.
[76] Transcript, April 16, 2018, at pp. 76/13 to 78/3
[77] PUB-NLH-033.
[78] A breakdown of the Nalcor Administration Fee by operating cost type is provided in Hydro's response to NP-NLH-028, Attachment 1.
[79] PUB-NLH-031.

Intercompany Transactions Costing Guidelines,[80] and the costs are recovered via the Nalcor Administration Fee.[81] Hydro submits that the use of shared services are prudent and in the best interests of its customers[82] and, therefore, should be included in its revenue requirement.

One of the drivers of increased labour-related costs in the last few years has been overtime.[83] Hydro implemented a new process to facilitate improved management of this cost as outlined in CA-NLH-215:

> There is an ongoing effort by Hydro to manage the amount of overtime, including: introduction of new measures to monitor overtime throughout the year; a review of the application of overtime compensation policy and actions to capture areas of improvement; implementation of targeted attendance support programs; and, a decrease in Hydro's operating overtime budgets included in its Test Years.

While there is a significant effort being made across the company to manage overtime, in utility operations there are instances when overtime is good business practice to ensure an appropriate level of reliability and/or effective cost management. This explanation was given by Ms. Hutchens in her testimony:

> The nature of our business is such that overtime will be required because, you know, storms don't happen just on a nine to five. They happen at two and three o'clock in the morning as well. And so, we need to – overtime is a – almost a – you know, there's a certain amount of overtime that is a requirement of our business. There's also overtime that is entirely appropriate in terms of job planning. For example, it might be better off, you know, getting a crew to work an extra two hours on a particular day on a particular job, if by going home at the regular work time they would have to come out the next day and, for example, spend a couple hours of driving to a site or – you know, and setting up and all that kind of stuff from a safety perspective. So, you know, there are times when overtime as well is entirely appropriate and least cost, and there's times when overtime is absolutely required because we have issues with the system. So, you know, our focus on overtime is about ensuring that we're making the best decisions we can and that we're responding to our customers' needs in terms of reliability.[84]

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[80] "2017 General Rate Application," Vol. II, Ex. 5.
[81] "2017 General Rate Application," Vol. I, Ch. 3, Sec. 3.7.2, at p. 3.38, fn. 76, notes that this fee was not required in 2015 as the organizational structure at the time was such that these services were provided by Hydro to all lines of businesses.
[82] NP-NLH-170.
[83] CA-NLH-141.
[84] Transcript, July 26, 2018, at pp. 51/17 to 52/21.

Short-Term Incentives Program

Hydro's Short-Term Incentives Program reflects prudent expenditures required to provide incentives for efficacious and innovative actions by Hydro senior managers and executive to achieve excellence in least-cost, reliable service for Hydro's customers.

Hydro's senior managers are eligible for short-term incentive compensation as part of an overall compensation package. This incentive is part of Hydro's overall compensation to ensure the company is competitive in the labour market and able to attract and retain senior leaders to drive business success.

The incentive opportunity is designed to influence performance in key areas that drive customer focus, reliability, and business success. Key performance indicators are reviewed annually and include a combination of corporate and divisional elements specific to the applicable line of business.

In its 2013 GRA filing, Hydro included the full recovery of its short-term incentives in its revenue requirement. Order No. P.U. 49(2016) disallowed the inclusion of these costs in the revenue requirement on the basis that Hydro could not reasonably justify that its performance contract model provided a demonstrable benefit to the customer and, therefore the customer should not bear those costs.[85] The Board stated Hydro's plan reflected a greater emphasis on the financial performance of the company, as well as that of the other Nalcor lines of business, rather than Hydro's reliability and customer satisfaction.[86]

In the 2017 GRA, Hydro has reviewed and updated the design of its 2017 Short-Term Incentives Program to have greater focus on indicators that benefit customers while still maintaining those that promote business success. The redesign addresses the concerns presented by the Board – as indicated in Hydro's response to PUB-NLH-124:

> Hydro has redesigned its short-term incentive plan to ensure clear and demonstrable benefit to the customers, an increase focus on reliability and customer service, and Hydro-only measures of performance related to the areas of: safety; reliability; financial/cost management; Hydro's activities related to the integration of Muskrat Falls assets; and regulatory.

[85] Order No. P.U. 49(2016), at p. 46/7-12.
[86] Order No. P.U. 49(2016) at pp.45/45 to 46/3.

As noted by Mr. Haynes in his testimony, all indicators have been redesigned to reflect the performance of Hydro only.

> All those targets there are basically Hydro only, they do not - there is nothing that Nalcor does that would reflect in there. I suppose potentially on the integration side if we were seen to be, if they deliver maybe something we wouldn't get done, but our intent is to do all these things here which are basically for Hydro customer's benefit, the safety reliability is solely Hydro. We don't have anything in there for Nalcor. There may be portions of this that will contribute to the overall Nalcor achievement, but basically that is completely independent of Hydro. Like our safety record would actually flow into theirs, obviously, some of the financial performance would flow up, but basically there is nothing flows down. This is solely a Hydro look. Our safety parameters are look at our safety performance and our goals and objectives to improve independently of Nalcor. The financial looks at only our objectives to actually meet our financial targets, and reliability is the same user, end user, which does incorporate the total impact of our actions on Newfoundland Power customers and ourselves, obviously.[87]

Hydro submits that providing incentives to Hydro's executive and senior managers to meet budget, produce cost savings, and focus on sustainable cost management provides value to the customers by lowering overall expenses which will, in time, have the effect of lowering revenue requirement and rates. Hydro's emphasis on its regulatory performance in its Short-Term Incentives Program brings focus to the regulatory environments under which Hydro operates, instills and gives an incentive to employees to meet regulatory deadlines and to achieve efficient regulatory processes. This will provide benefits to customers through more effective and efficient regulatory proceedings.

The enhancements to the Short-Term Incentives Plan promote least-cost and effective delivery of service to customers. Hydro submits that it is reasonable to recover 100% of its performance contract expenses in the 2018 and 2019 Test Years at amounts of $829,852 and $856,029, respectively.[88]

Innovation and Productivity Team Initiative

In response to the Board's observations in Order P.U. 49(2016), Hydro introduced an in-house Innovation and Productivity Team initiative to pursue efficiencies and improvements, with an aim to achieve long-term, sustainable improvements which reduce costs and provide value to Hydro's customers. This was accomplished in part through the introduction of the Lean Six Sigma Yellow Belt

[87] Transcript, April 24, 2018, at pp. 163/19 to 164/20.
[88] PUB-NLH-060.

Program.[89] The Innovation and Productivity Team is comprised of a select group of employees, representing a cross-section of Hydro's operations. The Team is tasked with gathering information and identifying productivity measures using the knowledge that lies within the company's employees. In total, 24 employees were trained to carry out this work, with four of them assigned to the initiative on a full-time basis. The remaining 20 employees maintained their current roles and assist in carrying out the initiative within their respective departments.

The mandate of the initiative is set out in Hydro's Innovation and Productivity Team's Terms of Reference.[90] The purpose of the Team is to identify ways to make the operations, management, and administration of Hydro more innovative, efficient, and productive. It can encompass changes in policies, practices, processes, organizational structure, technology and/or activities which instill a culture of productivity and efficiency.

Key to the initiative's success will be changing mindsets to focus on innovative ways to seek process improvements and cost reductions in every aspect of the company's activities. It is for this reason that broad-scale employee engagement is used to achieve success. This point was described by Ms. Hutchens when under cross examination by Mr. O'Brien, counsel for Newfoundland Power:

> MS. HUTCHENS: Yes. So, the core team are dedicated 100 percent to the innovation team. And they were taken out of their old roles and that was another, you know, we had to find those FTEs from somewhere; we didn't add them on extra. And their role is—it's kind of twofold. Their role as a team is to drive innovation and productivity in the organization. And there's the identification of opportunities, the examination of opportunities, so doing the detailed analytical assessments and we talked a little bit about that in NP-17. We talked about detailed assessments and analysis and the approach to that, in a generic way, not with specific reference to the team. And then they would work with the business to implement changes that would drive out innovation or productivity. So they basically develop a list of opportunities. They started with a list that we had been, sort of, working with and that we had been doing some work and started to drive out those opportunities, but they've also then gone outbound with the rest of the organization. The second piece of their mandate, and it's not said so much in the terms of reference as much as it is intoned because the terms of reference is something we felt that all employees would see and what not, but it's promoting the culture of innovation and productivity, you know. So, it's not just about taking opportunities and running them through to the end, but it's about helping employees as well as leadership and helping everybody to identify and implement productivity and

[89] Program recognized by the International Association for Six Sigma Certification.
[90] Undertaking #42, Att. 1, at p. 1.

> innovation opportunities. So, for example, they started with a roadshow. They actually went out into every office and did a presentation with employees on Lean Six Sigma kind of principles, you know, so it gave employees a little bit of a view of you know, what innovation and productivity is and a lot of people think innovation is about research and development and all that kind of stuff. It's not; it's about doing something different either with new tools or with tools you already have. . . . [91]

Hydro submits that the Innovation and Productivity initiative demonstrates its proactive approach to cost management. Hydro fully expects that this program will produce productivity gains in the coming years.

Cost Management and Budgeting

Hydro's budget process is structured, disciplined and rigorous, and assures that Hydro's operations and activities are focused on providing customers with maximum long-term value. The process includes a series of managerial review steps with appropriate review and approval by Hydro's Executive Team and Board of Directors including: [92]

- Operating costs prepared by business unit and submitted to general managers and ultimately to the Vice-Presidents of each area;
- Once operating costs are approved by the respective Vice-President, they are submitted as part of Hydro's total budget;
- A series of reviews of operating costs with each Vice-President, Finance, and the President of Hydro are conducted;
- All elements are consolidated and forecast income statement and balance sheet information is prepared;
- Budgets are consolidated and reviewed in detail with the Executive team;
- Depending on cost levels, there may be multiple reviews and iterations until the final numbers are approved;
- The budget is subject to various levels of review and approval by Managers, Vice-Presidents, and the President of Hydro; and
- Final review and approval is provided by the Hydro Board of Directors.

[91] Transcript, Jul 24, 2018, at pp.111/8 to 113/6.
[92] A description and the guidelines for the process are set out and attached in Hydro's response to PUB-NLH-051.

Aside from guidelines and process which includes detailed preparation and reviews, the budget outcomes are heavily influenced by the managerial tone and scrutiny provided by senior management, executives, and the Board of Directors. The goal is to achieve a prudent, sustainable, and least-cost operating budget that provides a balance of cost and reliability. Hydro submits that the test year budgets were developed using rigorous processes and reviews and provide for the correct balance and level of expenditures. In addition, specific budgetary guidelines were given with respect to the budgets for the 2018 and 2019 Test Years: [93]

- O&M costs for the Budget 2017 were not to exceed the 2016 Budget of $139.6 million. Structural salary and other increases would have to be offset by reductions in other areas;
- All requests for new FTEs required justification before inclusion in the budgets;
- All FTE requests were to be approved by General Managers and Vice-Presidents of the respective divisions prior to inclusion in the budgets;
- Executive level review and approval of all FTE requests would also be required prior to hiring;
- Salary and related labour cost estimates were provided by Human Resources to ensure data integrity;
- Professional services requests were to be completed using a pre-defined template that includes a description of the service and the vendor;
- Training was to be managed in total by Human Resources and all requests were to be submitted using a training template; and
- Travel costs were to include business critical and operational needs only.

During her testimony, Ms. Hutchens was asked about the process that applies to setting labour budgets. Ms. Hutchens detailed the level of rigour that is applied to labour budgets and the associated justification required for new positions, as well as the ongoing monthly review of the costs and cost drivers in the business. Emphasis was placed on the importance in distinguishing between cost cutting and sustainable management of cost drivers. Hydro's focus, under its current management structure, is on the latter.

[93] PUB-NLH-121.

MS. HUTCHENS: But I would suggest today that, you know, the next budget that we do that – you know, our managers very clearly understand the need for cost efficiencies and you know, there's some very strong messages that we send them through the gating process, through the vacancy allowance and the productivity allowance. Each of them, you know, has a piece of the vacation *(sic)* and the productivity allowance in their budgets. We have monthly meetings to review costs and challenge and talk about, you know, underlying cost drivers in the business and, you know, they're all expected to look at innovation and productivity in terms of, you know, what are some ways that we can do things better, faster, cheaper. So, that would absolutely be my expectation; that we would be looking at, you know, anything we could to reduce the costs. [94]

MR. O'BRIEN: Yeah.

MS. HUTCHENS: And because I can't comment about specifics in 2016. My understanding, there was a fair bit of rigour put in in 2016 and there was certainly some very strong messages sent by the executive at the time and you know, those messages were about, you know, reducing it. You know, keeping the budget at the minimum levels, those sorts of things. But again, coming off the Order in early 2017, we did go back and look and really challenged ourselves further in terms of what additional opportunities were there and certainly we focused in particular areas, but you know, that effort was – yes, there was a very significant level of rigour that went in. You know, there was a lot of detailed analysis about cost patterns, trends analysis, variances, those sorts of things, to try and understand where we might be able to trim things, change how we do things, that sort of thing. But, you know, there's a caution when you're doing that kind of process and it's the cost cutting caution and I know in PUB-54 there's a discussion around – I think Ms. Dalley referred to it as a little bit of a pendulum, you know.

So, in 2015, when we – you know, reliability became a very significant focus for the organization and, you know, coming off the outages, and that caused us to increase our operating expenditures and our capital expenditures as well in response to that. I think, you know, seeing the effects of that, then in 2016, it was "okay, well, we need to swing the pendulum back" and so, very strong cost messages sent in 2016 and the pendulum swung back. But, what happened in 2016, there was a bunch of what I would call not cost reduction, but cost cutting, and you know, you can reduce costs in two ways. You can just cut the costs, which aren't necessarily sustainable, or you can change your underlying cost drivers and ensure that any excess costs are removed but also underlying the change in the cost drivers. So, what drives your costs is really what you want to get at. So, in 2016, I would describe it more as a cost cutting kind of message. 2017, we tried to swing it back to the point where it's about cost management and sustainability and where we are today is looking at the sustainable cost reductions to ensure that we have -- the underlying cost drivers are altered in a way that we can, you know, minimize the costs going forward.[95]

[94] Transcript, Jul 24, 2018, at p.38/1-20.
[95] Transcript, July 24, 2018, at pp. 45/1 to 47/13.

Hydro is confident that its new corporate structure, monthly finance meetings, and new O&M reporting drive focus and accountability within its leadership to facilitate effective, least-cost management of the company. Hydro's budgetary process is rigorous and provides the structure within which management can assure that operating funds are spent where they can provide the greatest benefit and in amounts which provide least-cost service. Hydro is using specific and new methods to facilitate its employees to bring forward their ideas with respect to innovation and productivity, as previously discussed. The improvements achieved will bring tangible savings and will foster a corporate culture that maximizes value for Hydro's customers.

C.2.3.1.2. Operational Cost Management

2018 and 2019 Test Year Supply Costs

- **Hydro has determined its 2018 Test Year Supply Costs and 2019 Test Year Supply Costs based on the Expected Supply Scenario, in accordance with the Supplemental Settlement Agreement.**
- **To avoid duplication between the balances in the RSP and other supply cost deferral accounts and the calculation of the 2018 Test Year revenue requirement, Hydro has proposed:**
    - **the calculation of the RSP balances for 2018 be completed based on the 2015 Test Year cost of service inputs for the No. 6 fuel cost ($64.41[96] per barrel) and the Holyrood conversion factor (618 kWh per barrel);**
    - **No. 6 fuel supply costs for 2018 Test Year should reflect a 2015 Test Year No. 6 fuel cost of $64.41 per barrel and a 2015 Test Year Holyrood conversion factor of 618 kWh per barrel; and**
    - **Other 2018 Test Year supply costs for the Island Interconnected System and Isolated Systems be calculated based on the 2015 Test Year inputs used in calculation of the supply cost deferral account balances for 2018.**
- **No. 6 fuel supply costs for the 2019 Test year should be based on the most current fuel rider forecast[97] and the forecast 2019 Test Year Holyrood conversion factor of 583**

[96] Canadian Dollars ("CDN").
[97] "Supplemental Settlement Agreement," at p. 4, para. 19.

kWh per barrel.[98] Hydro's calculation of the RSP balances for 2019 should be based on the 2019 forecast Test Year cost of service inputs.

- **Gas turbine and diesel fuel supply costs for 2019 Test Year on the Island Interconnected System should reflect the forecast 2019 Test Year gas turbine and diesel fuel cost.**
- **The supply cost forecasts for the 2018 and 2019 Test Year for all systems are reasonable and ensure no duplication in recovery though the operation of deferral accounts and customer base rates.**
- **Upon approval of the 2017 GRA Compliance Application, the RSP should operate based on approved 2019 Test Year effective January 1, 2019.**

Overview

Hydro's supply costs principally consist of purchases of No. 6 fuel for Holyrood, purchases of diesel and gas turbine fuel, power purchases from other suppliers as well as off-island purchases over the LIL and the Maritime Link.

Table 1 provides the proposed 2018 Test Year supply costs and the projected 2019 Test Year supply costs to be used in setting customer rates reflecting the filing provided to the Board on October 26, 2018.

[98] "Supplemental Settlement Agreement," at p. 4, para. 16.

Table 1: Supply Costs by Type for 2018 and 2019 Test Years
($ millions)

Supply Cost	2018 Test Year Proposed	2019 Test Year Projected
Fuel Cost		
No. 6 Fuel[99]	147.7	137.9
Diesel and Gas Turbine Fuel[100]	21.0	28.5
Fuel Cost Subtotal	*168.7*	*166.4*
Power Purchases		
Power Purchases – On-Island[101]	59.2	62.3
Power Purchases – Isolated Systems[102]	3.0	3.9
Power Purchases – Labrador Interconnected[103]	1.5	1.7
Power Purchases – Off-Island[104]	7.7	6.4
Power Purchase Subtotal	*71.4*	*74.3*
Total Supply Costs	**240.1**	**240.7**

The 2019 Test Year fuel costs to be used in setting rates and the operation of the RSP for 2019 are not yet established and will depend on the fuel cost forecast that is filed with the Board when Hydro files its 2017 GRA Compliance Application.

<u>2018 Test Year Fuel Costs and Operation of Supply Cost Deferral Accounts</u>

The RSP, the Energy Supply Cost Variance Deferral Account, the Holyrood Fuel Conversion Deferral Account, and the Isolated Systems Deferral Account have operated during 2018 based on supply cost variances relative to the 2015 Test Year cost of service inputs.

To be consistent with the No. 6 fuel cost variances being recovered through the RSP during 2018, Hydro has calculated its No. 6 fuel supply costs for 2018 Test Year based on the 2015 Test Year No. 6 fuel cost of $64.41 per barrel and the 2015 Test Year Holyrood conversion factor of 618 kWh per barrel. Also, to ensure the RSP allocates load variation component variances consistent with the 2018 Test Year load forecast, Hydro has also proposed to use the 2018 Test Year load forecast in calculation of RSP load

[99] "2018 Cost Deferral and Interim Rates Application," at p. 8/14-15 (excludes ignition fuels, indirect costs and environmental fees). 2018 is operating under the 2015 Test Year RSP.
[100] "2018 Cost Deferral and Interim Rates Application," App. C, at p. 1/3-4 and App. D, at p. 1/3-4.
[101] "2018 Cost Deferral and Interim Rates Application," App. C, at p. 1/7, col. 3 and App. D, at p. 1/7, col. 3.
[102] "2018 Cost Deferral and Interim Rates Application," App. C, at, p. 1/7, col. 4-6 and App. D, at p. 1/7, col. 4-6.
[103] "2018 Cost Deferral and Interim Rates Application," App. C, at p. 1/6-7, col. 7 and App. D, at p. 1/6 and 7, col. 7.
[104] "2018 Cost Deferral and Interim Rates Application," App. C, at p. 1/9 and App. D, at p.1/9.

variations for 2018. Hydro proposes to make an adjustment to the 2019 RSP balance reflecting the use of the approved 2018 Test Year load forecast in the RSP calculations to be provided with its 2017 GRA Compliance Application.

Similarly, to avoid duplication between the balances in the Energy Supply Cost Variance Account, the Holyrood Fuel Conversion Deferral Account, the Isolated Systems Deferral Account, and the calculation of the 2018 Test Year Revenue Requirement to be recovered from customers, Hydro has proposed the 2018 Test Year energy supply costs which are subject to the operation of these deferral accounts (with the exception of the variances related to off-island purchases in 2018) be calculated based on the 2015 Test Year inputs.

Island Interconnected Supply Costs

Test Year Hydraulic Production

The hydraulic production forecast was developed consistent with the methodology used in the 2015 Test Year hydraulic production forecast. Hydro's hydraulic production forecast was not contested during the 2017 GRA. Hydro proposes that the Board accept the 2018 Test Year hydraulic production of 4,601 GWh and the 2019 Test Year hydraulic production of 4,600 GWh for the purpose of determining test year revenue requirements. The 2019 Test Year hydraulic production forecast should also be used for the operation of the RSP effective January 1, 2019.

Power Purchases – On-Island

Hydro purchases power and energy to meet Hydro's customers' requirements on the Island Interconnected System. On-Island power purchase expenses included in the 2018 and 2019 Test Years are $59.2 million and $62.3 million respectively.[105] Included in power purchase expense are costs associated with Capacity Assistance Agreements. The capacity assistance costs for the 2018 Test Year are $3.1 million[106] and $3.4 million[107] for the 2019 Test Year.

On-Island power purchases benefit customers through reduced Holyrood fuel requirements and the provision of capacity to provide reliable service to customers. Hydro submits these power purchases are

[105] "2018 Cost Deferral and Interim Rates Application," App. C, at p. 1/7 and App. D, at p. 1/7.
[106] "2017 General Rate Application," Vol. I, Sch. 3-VI
[107] PUB-NLH-178.

reasonable and the associated costs should be included in the 2018 and 2019 Test Year revenue requirements.

Hydro proposes continued capacity assistance agreements with Corner Brook Pulp and Paper Limited, Vale and Praxair[108] during the 2018 and 2019 Test Years. Hydro made a total of 17 requests for capacity assistance during the 2017-2018 winter period and these capacity requests helped to maintain generation reserves. [109, 110]

<u>Power Purchases – Off-Island</u>

Hydro is using Nalcor Energy Marketing ("NEM") to secure energy from external markets to supply customers. NEM has expertise in this area that is not available in Hydro. Hydro is confident that this approach is a prudent and cost effective course of action.

There are no costs of using NEM's services in the test year supply costs proposed to be recovered from customers. Any proposed future recovery of agency fees paid to NEM for its services will be subject to the Board's review.

Table 2 provides a summary of Off-Island Purchases and associated costs for the 2018 and 2019 Test years.

Table 2: Off-Island Purchases and Costs

	2018		2019	
	GWh[111]	Cost ($ millions)[112]	GWh[113]	Cost ($ millions)[114]
Recapture	69	0.2	667	1.5
Other Off-Island	83	7.5	49	4.9
Total	**152**	**7.7**[115]	**716**	**6.4**[116]

[108] The agreement with Praxair is for 2018 only.
[109] "Capacity Assistance Report – Corner Brook Pulp and Paper - Winter 2017-2018," May 30, 2018.
[110] "Capacity Assistance Report – Vale and Praxair – Winter 2017-2018," April 16, 2018.
[111] "2018 Cost Deferral and Interim Rates Application," at p. 5, Table 1.
[112] "2018 Cost Deferral and Interim Rates Application," at p. 6, Table 2.
[113] "2018 Cost Deferral and Interim Rates Application," at p. 5, Table 1.
[114] "2018 Cost Deferral and Interim Rates Application," at p. 6, Table 2.
[115] NP-NLH-343
[116] NP-NLH-344

Forecast savings as a result of off-island purchases are $9.818 million for 2018 and $107.46 million for 2019.[117]

Hydro submits that the costs incurred in acquiring off-island purchases to serve customers are prudent.

Holyrood Thermal Generation

Forecast production at Holyrood is a function of the Island Interconnected System forecast load less Hydro's own hydraulic generation, power purchases, and standby generation.

Table 3 provides a derivation of required Holyrood production for 2018 and 2019 by taking the Total Island Supply Requirement and subtracting hydraulic generation, power purchases and stand-by generation.

Table 3: Test Year Holyrood Generation Forecast

Line No.	Island Interconnected Supply Particulars	2018 Energy (GWh)	2019 Energy (GWh)
1	**Total Island Supply Requirement**	**7,223**	**7,235**
2	**NLH Hydroelectric Generation**	**4,601**	**4,600**
3	**Power Purchases**		
4	Nalcor Exploits and Star Lake	776	757
5	Wind	189	189
6	Corner Brook Pulp and Paper Ltd. CoGen.	51	67
7	Rattle Brook	15	15
8	*Subtotal On-Island Power Purchase*[118]	*1,031*	*1,028*
9	Other Off-Island Purchases	83	49
10	Recapture	69	667
11	**Total Power Purchases**	**1,183**	**1,744**
12	**NLH Standby Generation**[119]		
13	Gas Turbines	11	21
14	Diesels	0	1
15	**Total Standby Generation**	**11**	**22**
16	**Holyrood Generation** [120]	**1,427**	**869**

[117] PUB-NLH-176.
[118] "2017 General Rate Application," Vol. I, Ch. 3, Sch. 3-VI
[119] 2018 Standby Generation based on the 2015 Test Year. 2019 Test Year based on availability of Off-Island Power Purchases.
[120] Line 1 minus lines 2, 11, and 15.

The forecast Holyrood Generation is used to determine the test year quantity of No. 6 fuel to be consumed. The forecast cost of No. 6 fuel is a function of forecast fuel cost, volume of fuel consumed, and the Holyrood fuel conversion factor.

No. 6 Fuel: Holyrood Fuel Conversion

The forecast of Holyrood fuel consumption, and ultimately Holyrood production costs, is affected by the energy conversion factor for a barrel of No. 6 fuel. In 2016, The Board approved a 2015 Test Year conversion factor of 618 kWh per barrel.[121] Hydro used this conversion factor for its 2018 Test Year. Due to the changes in supply mix from off-island purchases, Hydro's settled 2019 Test Year conversion factor is 583 kWh per barrel.[122]

No. 6 Fuel: Test Year Costs

The 2018 Test Year cost of fuel was calculated based on the approved 2015 Test Year fuel cost and the 2019 Test Year fuel cost was estimated to be $92.50 per barrel, however, as per "Supplemental Settlement Agreement," at p. 4, para. 19 the 2017 GRA Compliance Application will be based on the most current fuel rider forecast.

Table 4: Derivation of Test Year No. 6 Fuel Cost

	2018 Test Year	2019 Test Year
Holyrood Generation (GWh)	1,427	869
Conversion Factor (kWh/bbl)	618	583
Barrels	2,309,288	1,490,487
Fuel Cost $/bbl	63.95[123]	92.50
Total No. 6 Fuel Costs ($000s)	**$147,679**	**$137,870**

Gas Turbine and Diesel

Hydro operates a number of gas turbines and diesel units on the Island Interconnected System, which provide additional long-term generation capacity and required generation reserves. The cost of diesel and gas turbine fuel has been included in the 2018 and 2019 Test Years at $3.6 million and $7.3 million respectively.[124]

[121] Order No. P.U. 49(2016), at p.32/25.
[122] "Supplemental Settlement Agreement," at p. 4, para. 16.
[123] Weighted Monthly 2015 Test Year No. 6 Fuel Costs.
[124] "2018 Cost Deferral and Interim Rates Application," App. C, at p. 27/3-4, col. 3 and App. D, at p. 37/3-4, col. 3.

Included in these forecast fuel costs for 2018 and 2019 are gas turbines fuel costs. Hydro submits that the cost of Island Interconnected gas turbine and diesel fuel be approved so that Hydro has the opportunity to recover prudently incurred supply costs on the Island Interconnected System.

Isolated Systems Supply Costs

The primary source of power supply for Hydro's isolated systems throughout the Province is diesel generation. The cost of diesel and gas turbine fuel has been included in the 2018 and 2019 Test Years at $17.1 million (calculated based on 2015 Test Year fuel price inputs) and $21.0 million respectively.[125]

Hydro, in its "2018 Cost Deferral and Interim Rates Application," updated its diesel and gas turbine price forecast reflecting the September forecast for the 2019 Test Year. Hydro will provide a further update based on the fuel forecast used in the 2017 GRA Compliance Application.

Labrador Interconnected Supply Costs

The majority of all energy consumed on the Labrador Interconnected System is purchased from Churchill Falls (Labrador) Corporation Limited ("CF(L)Co"). Power purchase costs from CF(L)Co are forecast to be $1.4 million and $1.5 million for 2018 and the 2019,[126] respectively. In addition to the power purchase costs from CF(L)Co, included in the 2018 and 2019 Test Years supply costs is $220,000[127] ($55,000 in 2018 and $165,000 in 2019) for a Capacity Assistance Agreement with Labrador Lynx Limited for Interruptible Load to support the Labrador East system. No issues were raised by any party in the hearing with respect the approach used to calculate these costs.

In accordance with the Labrador Settlement Agreement, Hydro will update its load forecast and its supply cost forecast for the Labrador Interconnected System in the 2017 GRA Compliance Application.

[125] "2018 Cost Deferral and Interim Rates Application," App. C, at p. 27/3-4, col. 4-6 and App. D, at p. 37/3-4, col. 4-6.
[126] "2018 Cost Deferral and Interim Rates Application," App. C, at p.27/6, col. 7 and App. D, at p.37/6, col. 7.
[127] "2018 Cost Deferral and Interim Rates Application," App. C, at p.27/7, col. 7 and App. D, at p. 37/7 col. 7.

Management of the Rural Deficit

Increases in the Rural Deficit have been due primarily due to increases in depreciation and return on investment. Hydro's Conservation and Demand Management ("CDM") activities and overall operational efficiencies assist in controlling the Rural Deficit.

Growth in Rural Deficit

The Rural Deficit has increased from $59.4 million in the 2015 Test Year[128] to $65.8 million in the 2019 Test Year under the Expected Supply Scenario.[129] This represents an increase of approximately 11% from the 2015 Test Year. Hydro's response to NP-NLH-191 indicates that the Rural Deficit increased by approximately $7.5 million between 2016 and the 2019 Test Year as a result of depreciation and return on capital investments.[130] While overall growth in the Rural Deficit between 2016 and the 2019 Test Year is $8.4 million,[131] depreciation and return on capital investments are the primary drivers of the increase.

Measures to Control the Rural Deficit

Hydro's 2015, 2016, and 2017 Rural Deficit Annual Reports were provided as Appendices F, G, and H, respectively, of Schedule 1 to Hydro's "Application for Deferral of 2015, 2016 and 2017 Supply Costs." The reports summarize the initiatives undertaken by Hydro to limit the growth in the Rural Deficit. These include a number of internal energy efficiency initiatives, CDM programs, and capital investment.

CDM programs, which reduce demand and energy consumption, are a critical component to the management of the Rural Deficit. Hydro's internal energy efficiency initiatives have contributed to energy savings of 336 MWh valued at approximately $1.0 million from 2015 to 2017, inclusive. Hydro's CDM programs, such as the Isolated Systems Community Energy Efficiency Program and the Isolated

[128] "2017 General Rate Application," Vol. I, Ch. 3, at p. 3.31.
[129] "2018 Cost Deferral and Interim Rates Application," App. D, at p. 3/12, col. 5.
[130] Hydro's response to NP-NLH-191 indicates that: "*The increase in depreciation expense between 2016 and the 2019 Test Year is primarily due to: (i) increased asset investment on the Island Interconnected System ($638 million additional investment over the 2017 to 2019 period) resulting in an increase of $4.2 million in depreciation expense allocated to Hydro's Rural Systems; and (ii) increased asset investment on Hydro's Rural Isolated systems ($62 million additional investment over the 2017 to 2019 period), resulting in an increase of $3.3 million in depreciation expense.*"
[131] 2017 "Rural Deficit Annual Report," at p. 2, Table 1, shows the 2016 Rural Deficit of $57.4 million.

Systems Business Efficiency Programs, have contributed to energy savings of 3,438 MWh valued at approximately $5.5 million from 2015 to 2017, inclusive.[132]

Additionally, based on the success of its pilot LED street light replacement project for the Town of Nain,[133] Hydro intends to expand the use of LED streetlights in isolated communities. A cost-benefit analysis of replacing the lighting in various communities versus the status quo determined that replacement of the lighting had positive net present value and would provide a total savings of $374,429.[134]

<u>*Alternate Sources of Supply*</u>

Hydro continues to seek more cost-effective sources of supply. As noted in Hydro's evidence:

> . . . 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.[135]

Hydro is committed to undertaking 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.[136]

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[132] Undertaking #32.
[133] As indicated in the 2017 "Rural Deficit Annual Report," at pp. 8 to 9, the Nain street light retrofit yields savings of approximately 45 MWh, offsetting approximately 12,000 litres of fuel consumption.
[134] 2017 "Rural Deficit Annual Report," at p. 8.
[135] "2017 General Rate Application," Vol. I, Ch. 3, at p. 3.32.
[136] "2017 General Rate Application," Vol. I, Ch. 3, at p. 3.33.

Use of Embedded Contractors

Hydro uses embedded contractors as a cost-effective method of resource management.

Hydro's position on embedded contractors is outlined in Hydro's response to PUB-NLH-136. Embedded contractors are used to supplement its workforce, when required, to execute its annual work plan. Hydro first assigns and fully loads its employees to specific work in the annual work plan and the balance of the resource plan is filled through embedded contractors.

The evidence demonstrates that Hydro conducts ongoing reviews to ensure it maintains a cost-effective balance between contractors and employees. In Mr. Gardiner's testimony, he outlined a previous review through which Hydro identified the opportunity for cost savings through the transition of work from 11 embedded contractors to 11 FTEs, resulting in a savings of 15%.[137]

Hydro's approach to retaining the services of an embedded contractor is largely similar to its approach in hiring an employee – there is a gate-in process and the criteria used to determine that an embedded contractor is needed is the same. This ensures that Hydro's management of its resources is consistent with balancing the provision of reliable service with its least-cost obligation.

Hydro recognizes the importance of having full-time individuals as employees and continues to work to adjust the number of FTE employees to support a sustained level of work plan activity, thus reducing reliance on embedded contractors. Hydro submits its strategy for use of embedded contractors is prudent.

C.3. Cost of Service, Rates, Rules, and Regulations Issues

There are a number of issues related to Hydro's cost of service studies, rates, rules, and regulations which the Parties agreed to by way of settlement and which still require approval of the Board. These issues are summarized in the following sections.

[137] Transcript, July 16, 2018, at pp. 49 to 56.

C.3.1. Settled Items

C.3.1.1. Specific Assignment

On December 21, 2017, Hydro filed a report detailing its review of specifically assigned assets on the Island Interconnected System. This report identified changes which were required to the classification of assets between common and specifically assigned. The Parties agreed to the assignment of assets as common or specifically assigned as proposed in the 2017 GRA and amended by Hydro's report "Review of Industrial Customer Specifically Assigned Assets," filed on December 21, 2017. [138,139]

C.3.1.2. Cost of Service

The Parties agreed on the cost of service methodologies used in the "2017 General Rate Application," Vol. III, Ex. 14 and 15 (Test Year Cost of Service for 2018 and 2019, respectively) with respect to:

- The classification of wind energy purchases as 100% energy related;[140]
- The specific assignment of the frequency converter to Corner Brook Pulp and Paper Limited;[141, 142]
- The 2017 GRA proposed methodology for determining the test year operating and maintenance costs to be recovered through specifically assigned charges to Industrial Customers;[143] and
- The functionalization of transmission assets TL 267 as 100% demand related.[144]

C.3.1.3. 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 expected Hydro to address the Rural Deficit allocation methodology in its cost of service report to permit all parties to have further

[138] "Settlement Agreement," at p. 3, para. 15.
[139] Hydro's report was refiled on March 5, 2018. Hydro also submitted the "Customer Cost Allocation Impacts – Asset Functionalization Review," February 21, 2018.
[140] "Supplemental Settlement Agreement," at p. 2, para. 7.
[141] "Supplemental Settlement Agreement," at p. 2, para. 7.
[142] Applies only to the derivation of the 2018 Test Year due to the sale of the asset approved by the Board in Order No. P.U. 26(2018).
[143] "Supplemental Settlement Agreement," at p. 2, para. 7.
[144] "Supplemental Settlement Agreement," at p. 2, para. 7.

opportunity to provide input as part of the review of that report.[145] In its 2017 General Rate Application, Christensen Associates Energy Consulting reviewed the methodology and supported Hydro's revenue requirement allocation proposal.[146]

The Parties settled this matter and it was agreed that the revenue requirement method to allocate the Rural Deficit between Newfoundland Power and the Labrador Interconnected System approved by Order No. P.U. 49(2016) should be applied in the Cost of Service Methodology for the 2018 and 2019 Test Years.[147] For the 2019 Test Year, the Rural Deficit allocation is projected to be 95.5% to Newfoundland Power and 4.5% to Rural Labrador Interconnected.[148]

C.3.1.4. Rules and Regulations

In order to be consistent with the rules and regulations of Newfoundland Power, Hydro proposed changes to sections 9(b) and 9(c) of its Rules and Regulations for Rural Customers. These changes, agreed to by the Parties,[149] include the following changes:

- Section 9(b) - revised to be consistent with Newfoundland Power and remove the requirement of payment in advance for temporary service charges; and
- Section 9(c) - revised to be consistent with Newfoundland Power and remove the requirement of payment in advance for special facilities.

In addition, the Parties agreed to a revision to Section 16(a) which Hydro proposed to permit automatic rate changes for the Burgeo School and Library, consistent with rate changes approved for Newfoundland Power's customers.[150]

The current RSP rules require that actual billing data from Hydro Rural Customers be used in the calculation of the RSP Rural Rate Alteration on a monthly basis. Hydro proposed to modify the RSP rules to permit the use of test year data in computing the RSP Rural Rate Alteration. Hydro's proposal will materially reduce the administrative effort in preparing the monthly RSP report and will not have a

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[145] Board Order No. P.U. 49(2016), at p. 105/20-22.
[146] "2017 General Rate Application," Vol. II, Ex. 13, at pp. 21 to 26.
[147] "Settlement Agreement," at p. 3, para. 16.
[148] "2018 Cost Deferral and Interim Rates Application," App. D, at p. 9/4-5.
[149] "Settlement Agreement," at p. 4, para. 19.
[150] "Settlement Agreement," at p. 4, para. 19.

material impact on RSP transfers.[151] The Parties agreed to this change with effect from January 1, 2018.[152]

C.3.1.5. Customer Bill Presentation

In accordance with Board Order No. P.U. 49(2016), Hydro filed a report on the identification of the rural subsidy on customers' bills with its 2017 GRA.[153] The Parties agreed to defer the consideration of whether information on the rural deficit should be included on customers' bills to another proceeding or a future general rate application.[154]

C.3.1.6. Newfoundland Power's Wholesale Rate

In its 2017 GRA evidence, Hydro proposed an increase of Newfoundland Power's firm demand charge of $0.50 to $5.25 per kW in the 2019 Test Year.[155] The Parties agreed that Newfoundland Power's demand charge should equal $5.00 per kW of billing demand,[156] an increase of $0.25 from the currently approved rate. The Parties also agreed that Newfoundland Power's second block firm energy rate should be determined consistent with historical practice, based on the most current fuel rider forecast divided by the approved 2019 Test Year Holyrood No. 6 fuel conversion rate (expressed on a cent per kWh basis).[157] Given the potential increase in the second block rate relative to the currently approved rate of 10.422 cents per kWh, the Parties agreed that the sizing of Newfoundland Power's first block energy component should be determined in consultation with Newfoundland Power prior to the filing of Hydro's 2017 GRA Compliance Application.[158,159] This approach will allow Hydro and Newfoundland Power to work collaboratively to design an appropriate first block energy rate once the second block energy rate is known.[160]

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[151] "2017 General Rate Application," Vol. I, Ch. 5, Sec. 5.6.7, at p. 5.23.
[152] "Settlement Agreement," at p. 4, para. 18.
[153] "2017 General Rate Application," Vol. II, Ex. 4.
[154] "Settlement Agreement," at p. 4, para. 20.
[155] "2017 General Rate Application," Vol. I, Ch. 5, Sec. 5.6.8, at p. 5.24.
[156] "Supplemental Settlement Agreement," at p. 2, para. 9.
[157] "Supplemental Settlement Agreement," at p. 3, para. 9.
[158] Newfoundland Power's approved 2019 Test Year revenue requirement not recovered through the demand charge and the end-block energy charge will be used to compute the first block energy charge.
[159] "Supplemental Settlement Agreement," at p. 3, para. 9.
[160] Without adjusting the size of the first block, a large increase in Newfoundland Power's second block rate could result in a negative first block rate.

In addition, the Parties agreed that the wholesale rate will continue to include the Generation Credit and Curtailable Credit in computation of the billing demand of Newfoundland Power in the amount of 118,054 kW for the 2018 Test Year and the 2019 Test Year, as proposed in Hydro's 2017 GRA Evidence.[161]

C.3.1.7. Labrador Industrial Rate Design

With respect to the design of rates for Labrador Industrial Customers, the Parties agreed that the existing design should continue to apply and the changes proposed by Hydro in the 2017 GRA will not be implemented in this proceeding.[162]

C.3.1.8. Corner Brook Pulp and Paper Pilot Agreement

In the 2017 GRA, Hydro had proposed the conclusion of the Corner Brook Pulp and Paper Pilot Agreement;[163] however, the Parties agree that the generation credit 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) should be continued on a pilot basis.[164]

C.3.1.9. Amortization of Revenue Deficiency or Excess

Hydro is currently forecasting either a test year revenue deficiency or test year excess revenues for a number of customer classes.[165] With respect to Newfoundland Power and Industrial Customers, the Parties agree that any test year revenue deficiency or test year excess revenues arising from the difference between the actual rates charged in 2018 and those which recover Hydro's approved 2018 revenue requirement by customer class will be recovered or refunded through rate riders determined separately for each customer class. The rate riders will be computed reflecting a 20-month period beginning with the effective date of final rates as approved by the Board in the Application.[166]

Hydro submits that the same approach should be taken for any 2019 revenue deficiency or excess, the amount of which will be determined through Hydro's 2017 GRA Compliance Application.

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[161] "Supplemental Settlement Agreement," at p. 3, para. 9.
[162] "Settlement Agreement," at p. 4, para. 17.
[163] "2017 General Rate Application," Vol. I, Ch. 5, Sec. 5.3.1, at p. 5.7.
[164] "Supplemental Settlement Agreement," at p. 2, para. 8.
[165] "2018 Cost Deferral and Interim Rates Application," at p. 11, Table 4.
[166] "Supplemental Settlement Agreement," at p. 4, para. 20.

For Hydro Rural Government Diesel Customers, the Parties agree that any class revenue deficiency or excess revenues arising from the difference between the actual rates charged in 2018 and those which recover Hydro's approved 2018 Revenue Requirements by class will be recovered or refunded through cost amortizations reflected in customer rates and computed reflecting a 20-month period beginning with the effective date of final rates as approved by the Board.[167] Hydro submits that the same approach should be taken for any 2019 revenue deficiency or excess, the amount of which will be determined through Hydro's 2017 GRA Compliance Application.

For Hydro's Labrador Customers, the Parties agree to amortize the 2018 revenue deficiency over 24 months, beginning with the effective date of the 2017 GRA final rates approved by the Board.[168] Hydro submits that the same approach should be taken for any 2019 revenue deficiency or excess, the amount of which will be determined through Hydro's 2017 GRA Compliance Application.

Hydro believes that the amortization periods noted in the Supplemental Settlement Agreement and the Labrador Settlement Agreement are still appropriate.[169] Hydro submits that these items should be approved by the Board in accordance with the Settlement Agreements reached with the Parties.

C.4. Supply Cost Deferrals and Recovery Mechanisms

Hydro is seeking approval of: (i) a Revised Energy Supply Cost Variance Deferral Account definition, (ii) recovery of increased 2018 supply costs resulting from lower than forecast off-island purchases, and (iii) recovery of the deferred supply cost balances in the Energy Supply Cost Variance Deferral Account, the Holyrood Conversion Rate Deferral Account, and the Isolated Systems Cost Variance Deferral Account, together known as the "Deferred Supply Costs."

C.4.1. Settled Items

C.4.1.1. Revised Energy Supply Cost Deferral Account Definition

Under the Expected Supply Scenario, the forecast savings associated with off-island power purchases will be included in forecast customer rates. Given the price differential between the cost of Recapture Energy and all other sources of supply, as well as the potential for variations in the price and availability

[167] "Supplemental Settlement Agreement," at p. 4, para. 21.
[168] "Labrador Settlement Agreement," at p. 2, para. 9.
[169] PUB-NLH-182.

of market energy, variations between the actual and forecast quantities and prices of off-island power purchases can have a material impact on Hydro's supply costs.[170] The proposed Revised Energy Supply Cost Variance Deferral Account would permit Hydro to defer supply costs variances which result from variations in off-island power purchases.

The Parties agreed to the implementation of the proposed Revised Energy Supply Cost Variance Deferral Account as filed in Appendix L of Hydro's Additional Cost of Service Information dated March 22, 2018.[171] The definition agreed to in the Supplemental Settlement Agreement was revised in the 2018 Cost Deferral and Interim Rates Application – Revision 2 to reflect that the account will not include any expenditure related to the use of the LIL or LTA under the Interim Transmission Funding Agreements, as per OC2018-213. The effective date of the Revised Energy Supply Cost Variance Deferral Account is to be determined by the Board.[172]

C.4.1.2. 2015, 2016, and 2017 Deferred Supply Costs- Recovery Methodology

The Parties were able to agree on the methodology by which the 2015, 2016 and 2017 deferred supply costs ultimately determined to be found prudent by the Board ("Approved Deferred Supply Costs") should be recovered. With respect to the allocation of costs, the Parties agreed that that the Approved Deferred Supply Costs should be allocated between customer classes in a manner consistent with the fuel cost allocation methodology used in the RSP. The allocation percentage will be based on the RSP energy allocators consistent with the year in which the Approved Deferred Supply Costs were incurred. Further, the Parties agreed that, consistent with the allocation methodology in the RSP, the net portion of the Approved Deferred Supply Costs allocated to Labrador as of December 31, 2017 (approximately $60,000) will be written off to Hydro's net income upon receipt of the 2017 GRA Order.[173] As the 2017 GRA Order will be issued in 2019, Hydro proposes the Labrador adjustment to net income occur in 2019.

With respect to the means by which costs are recovered from Hydro's customers, the Parties agreed that the Approved Deferred Supply Costs allocated to each of Newfoundland Power and the Island Industrial Customers will be recovered through rate riders determined separately for each customer class and computed reflecting a 20-month recovery period beginning with the effective date of the 2017

[170] NP-NLH-288.
[171] Supplemental Settlement Agreement, at p. 4, para. 18.
[172] Supplemental Settlement Agreement, at p. 4, para. 18.
[173] Labrador Settlement Agreement, at p. 2, para. 8.

GRA final rates approved by the Board. Hydro notes that given the materiality of the Deferred Supply Costs (approximately $65 million) to be recovered over the amortization period, recovery of these costs over a shorter amortization period would materially increase the required rate increase to customers on the Island Interconnected System at the time of 2017 GRA final rate implementation. Therefore, Hydro believes it continues to be appropriate to use the 20-month amortization period consistent with the Supplemental Settlement Agreement.

In addition, the Parties agreed that Newfoundland Power's portion of the credit balance of the Isolated Systems Deferral Account as of December 31, 2017 should be calculated based on the proportion of the 2018 Test Year Rural Deficit allocated to Newfoundland Power, and that this credit will be applied to reduce the 2018 Revenue Deficiency approved by the Board to be recovered from Newfoundland Power.[174]

Hydro submits that these items should be approved by the Board in accordance with the settlement agreements reached with the Parties.

C.4.2. Unresolved Issues

C.4.2.1. 2018 Savings from Off-Island Purchases

As noted in Hydro's response to PUB-NLH-176, estimated deliveries of off-island power purchases in 2018 were projected to be below Hydro's forecast by approximately 43 GWh.[175] As a result of this variance, there was an estimated reduction in net savings from off-island purchases of $2.3 million in 2018 relative to the 2018 forecast reflected in the "2018 Cost Deferral and Interim Rates Application," October 26, 2018.[176] Hydro submits that it should be permitted to recover these prudently incurred supply expenses.

Hydro submits that this recovery could be addressed in one of two ways: (1) approval of the Revised Energy Supply Cost Variance Deferral Account definition effective January 1, 2018[177] or, (2) include the increased 2018 supply costs in the 2018 Revenue Deficiency to be addressed in Hydro's 2017 GRA

[174] Supplemental Settlement Agreement, at p. 3, para. 10 and 11.
[175] PUB-NLH-176, Table 1.
[176] PUB-NLH-176.
[177] In the Supplemental Settlement Agreement, at p. 4, para. 18, the Parties agreed to the implementation of the Revised Energy Supply Cost Variance Deferral Account with an effective date to be determined by the Board.

Compliance Application. Alternative 1 would result in lower GRA final customer rates for Island Interconnected System customers with a deferral of 2018 fuel expenses being charged to the Revised Energy Supply Deferral Account in 2018 for future recovery from customers. Alternative 2 would reflect the additional 2018 supply costs in determining 2018 Test Year revenue requirement.

Hydro submits that Alternative 2 is consistent with the concept of intergenerational equity in matching the costs incurred in 2018 with the 2018 Test Year revenue requirement and is Hydro's recommended approach. This approach is also consistent with the Board's approved approach for recovery of the 2014 deferred capacity related costs. In Order No. P.U. 49(2016), the Board approved the inclusion of the 2014 deferred capacity-related costs in the determination of the 2014 Test Year revenue requirement.[178]

C.4.2.2. 2015, 2016, and 2017 Deferred Supply Costs Recovery

On March 23, 2018 Hydro applied for recovery of approximately $65.4 million in supply costs associated with Deferred Supply Costs.[179] On April 9, 2018 the Board sent notice to the Parties that this application would be addressed in Hydro's 2017 GRA. As a result, through the 2017 GRA, Hydro is seeking approval for recovery of the following account balances related to each year's transactions:[180]

- 2016 Isolated Systems Supply Cost Variance Deferral Account credit balance of $2,186,570.00;
- 2017 Isolated Systems Supply Cost Variance Deferral Account credit balance of $1,106,821.00;
- 2015 Energy Supply Cost Variance Deferral Account debit balance of $14,200,429.00;
- 2016 Energy Supply Cost Variance Deferral Account debit balance of $24,462,996.00;
- 2017 Energy Supply Cost Variance Deferral Account debit balance of $20,134,732.00;
- 2015 Holyrood Conversion Rate Deferral Account debit balance of $3,582,048.00;
- 2016 Holyrood Conversion Rate Deferral Account debit balance of $2,150,665.00; and
- 2017 Holyrood Conversion Rate Deferral Account debit balance of $4,163,799.00.

[178] Board Order No. P.U. 49(2016), at pp. 81 to 82, Sec. 13.2.
[179] Revised April 25, 2018.
[180] Hydro is not seeking recovery of the 2015 Isolated Systems Supply Cost Variance Deferral Account balance as it was $0.00.

C.4.2.2.1. Energy Supply Cost Variance Deferral Account

Hydro's deployment of its assets is consistent with its requirement for it to provide least-cost, reliable service to its customers.

The Energy Supply Cost Variance Deferral Account permits Hydro to defer variances from the approved test year in the price of supply costs on Hydro's Island Interconnected System. This deferral account is comprised of three main sections: (1) variations in both price and volume of standby thermal generation; (2) variations in volume only from power purchases; and, (3) fuel cost variations at Holyrood as a result of variations in energy production from sources specifically covered by the Energy Supply Cost Variance Deferral Account. Hydro's final argument on the Energy Supply Cost Variance Deferral Account focuses on the costs associated with gas turbines as these costs are the most material contributor to the account balance.

Approximately $59 million has accumulated in the Energy Supply Variance Deferral Account for the years 2015 through 2017. A material contributor to the accumulation of this balance has been changes Hydro made to its operation of standby generation when conventional generation[181] is not adequate to meet forecast system requirements (customer requirements, spinning, and non-spinning reserve).[182]

In 2015, following the power disruptions during the period from January 2 to 8, 2014 as well as the March 4, 2015 Avalon Voltage Collapse event, Hydro undertook a review of its reliability approach and practices, specifically where it related to Island spinning/regulating reserves and System Operating Limits. Several improvements resulted from this review:

- The Island Interconnected System 'Generation Reserves' instruction (T-001 now BA-P-012) was reviewed and modified;[183]
- An Avalon Reserves and stakeholder notification procedure (T-096) was developed and implemented;[184] [185]

[181] Conventional generation refers to available generation excluding any gas turbine generation or interruptible arrangements in place, and wind generation beyond current day.
[182] Spinning reserve is the unloaded generation that is synchronized and ready to serve additional demand.
[183] "Application for Deferral of 2015, 2016, and 2017 Supply Costs," Sch. 1, at p.7/23-26.
[184] This procedure was discontinued as of the completion of the construction and in-service of the third transmission line from Bay d'Espoir to the Avalon (TL 267) near the end of 2017.
[185] "Application for Deferral of 2015, 2016, and 2017 Supply Costs," Sch. 1, at p.7/23-26.

- Hydro commenced its practice of daily assessments of Island and Avalon reserves, with communications and stakeholder notifications as appropriate;[186] and,
- The determination of the requirements for gas turbine operation became more regimented and gas turbines were dispatched in advance of contingencies in keeping with Hydro's reliability approach.[187]

For many years the Holyrood units were dispatched and, for the most part, were sufficient to maintain the System Operating Limits for the transmission corridor between Bay d'Espoir and the Avalon Peninsula.[188] The Holyrood units were started and stopped primarily based on Avalon load requirements. However, with the Avalon load growth over recent years and the decline in performance of the Holyrood units (particularly in 2016-2017), the amount of available generation at the Holyrood became insufficient to maintain the System Operating Limits in this corridor. This resulted in materially increased generation requirements from higher cost gas turbines. These units were operated in advance of the worst case contingency when there was potential for transmission line overloads, voltage collapse, or dynamic instability that could result in significant and prolonged customer impact.[189]

Aligned with best practice reliability standards, Hydro operates its generation fleet (including thermal generation, emergency and standby generation) to position the power system to withstand the single worst contingency event. This practice has lowered both the risk of customer impact and the magnitude of customer impacts should a contingency occur. Operation of Hydro's gas turbines in this manner was not contemplated in the 2015 Test Year forecast prepared in 2014; therefore the cost is not being recovered through current customer rates and a material balance owing from customers has accumulated in the Energy Supply Cost Variance Deferral Account.

With respect to the prudence of the increased gas turbine fuel costs incurred over the period 2015 to 2017, Hydro submits that it requires the ability to dispatch any and all of its installed assets to reliably

[186] NP-NLH-325.
[187] NP-NLH-303.
[188] This was the primary driver of gas turbine operation during the 2015-2017 timeframe – prior to the construction of TL 267 near the end of 2017.
[189] NP-NLH-324, Attachment 1.

supply customers, consistent with good utility practice. As noted by Ms. Williams testimony of July 17, 2018:[190]

> MR. O'BRIEN: Okay. So, if you were going to—and I assume your management decisions in operating stand-by generation, you would have wanted to do so on a cost benefit basis, like I would imagine, is that fair?
>
> MS. WILLIAMS: It's our least cost dispatch and we don't want to start it up unless we absolutely have to. And the reason why the gas turbines or, in particular, let's call it Holyrood, gas turbine, is being used is because of, you know, Holyrood is at its end of life. It is experiencing issues. We have essentially had to treat it in that fashion. And, I mean, you have the constraint that previously existed; you have the load on the Avalon, you know. In order to function with the current system in the last couple of years, we really didn't have much choice but to dispatch the gas turbines. I think it's about 20 percent of our installed capacity. When you do have an issue and its part of your reserve planning, you don't expect to never run. You expect to run it and I understand again, the magnitude is significant. You know, prior to the last few years, you know, Holyrood would have been used to help with spinning reserve and, you know, those costs would be flowing through the RSPs, so I think it's the magnitude of why we've had to run the gas turbines. The philosophy is not radically different than say, it would have been historically, it's that we have gone to a point in the last couple of years where we've had to use the gas turbine because of what was going on in the Avalon.

As noted by Ms. Williams, Hydro's generation is dispatched in least cost order. The degree to which the generation is dispatched under the economic priority guidelines depends on a number of factors including system demand requirements, the status of other generation (e.g., forced and planned outages to generating units and deratings), and transmission configurations (e.g., forced and planned outages to major transmission lines). Gas turbines are the highest cost source, and are dispatched when conventional generation (hydraulic generation or Holyrood) is insufficient to meet Hydro's reliability approach.

On May 24, 2018, the Board advised the Parties that it had retained Liberty to review and provide an opinion on Hydro's operational philosophy and practices regarding the operation of standby generation to meet forecast system requirements. On June 22, 2018, Liberty issued its report on its Analysis of Hydro's Energy Supply Cost Variance Deferral Account. In its report, Liberty noted:

[190] Transcript, July 17, 2018, at pp. 105/8 to 106/19.

> . . . Hydro's adoption of N-1 and the higher spinning reserve requirement simply reflected a practice in near-universal use in the industry. It is difficult to challenge the prudence of a decision that simply aligns one's practices with the rest of the industry. While critical of the failure to address costs at the time, we simply could not conclude with a reasonable degree of certainty that doing so would have led to a different decision, and thus it is our opinion that the decision Hydro made fell within the range of alternatives a reasonable utility manger would consider.[191]

Hydro submits that its approach to generation dispatch is consistent with the provision of least cost reliable service and is supported by Liberty's conclusion that Hydro's gas turbine costs are not imprudent.

Hydro submits that the evidence also addresses the Board's concerns from Order No. P.U. 39(2017) with respect to the costs and benefits of Hydro's approach to generation dispatch to demonstrate that the supply costs incurred for 2015, 2016, and 2017 were prudently incurred in the provision of reliable service to customers.

Hydro submits that the balance in the Energy Supply Cost Variance Deferral Account for the period 2015 to 2017 was prudently incurred and respectfully requests that the Board approve recovery consistent with the method provided for in the Supplemental Settlement Agreement.[192]

C.4.2.2.2. <u>Isolated Systems Cost Variance Deferral Account</u>

Hydro purchases diesel fuel to supply customers on its isolated systems. Diesel fuel is a commodity and its price is set by market forces which can fluctuate greatly. This volatility and corresponding fuel price variance is beyond Hydro's control. As noted by the Board in Order No. P.U. 49(2016) *"[t]he Board accepts Hydro's evidence that there is significant volatility in the price of diesel fuel on its Isolated systems which is beyond Hydro's control and that the risk is material."*[193]

The Isolated Systems Cost Variance Deferral Account permits Hydro to defer variances from the approved test year in the price of supply costs in Hydro's isolated systems. The Isolated Systems Cost Variance Deferral Account provides for disposition of approximately $3.3 million in savings to customers

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[191] "Analysis of Hydro's Energy Supply Cost Variance Deferral Account," The Liberty Consulting Group, June 22, 2018, at pp. 1 to 2.
[192] "Supplemental Settlement Agreement", p. 3, para. 13.
[193] Order No. P.U. 49(2016), at p. 115/30-31.

as a result of lower than forecasted diesel fuel prices and power purchases in isolated communities. Hydro submits that these balances should be approved for disposition in accordance with the settled recovery methodology.

C.4.2.2.3. Holyrood Conversion Rate Deferral Account

The Holyrood Conversion Rate Deferral Account permits Hydro to defer costs that result from differences between the actual and Test Year No. 6 fuel conversion rate. The Holyrood conversion rate can be affected by unit loading and fuel BTU content. Generally higher unit loading at Holyrood will improve the conversion rate and result in fuel savings, and, conversely, lower unit loading at Holyrood will reduce the conversion rate and result in higher fuel costs.

The Board, in Order No. P.U. 49(2016) stated the following with respect to the Holyrood Conversion Rate Deferral Account:[194]

> In the circumstances the Board accepts that variances associated with the Holyrood conversion rate may be material, particularly given the new supply sources recently added to the system and the fact that the Holyrood thermal generating station is an aging asset. While the Board accepts that Hydro does have some control over the Holyrood conversion rate there are many other factors in operating the Island Interconnected system which can impact the Holyrood conversion rate which are outside of Hydro's control, for example load and changes in the heat content of the fuel.

The Holyrood Conversion Rate Deferral Account has accumulated approximately $9.9 million in costs as a result of a lower than forecast conversion rate at Holyrood. This balance is primarily due to lower unit loading than what was forecast in Hydro's approved 2015 Test Year as a result of operating of a Holyrood unit at minimum loads during the summer months in order to support Avalon reserves which supports system reliability for customers. Hydro submits that these costs should be approved as prudent to be recovered from customers.

C.5. Other

C.5.1. Timing of Next General Rate Application

At this time, completion of the Muskrat Falls Project is anticipated for September 2020. Ideally, rates for Hydro's customers that include the costs of the Muskrat Falls Project in revenue requirement would be

[194] Board Order No. P.U. 49(2016), at pp.121/39 to 122/2.

implemented at that time. This would necessitate filing the next General Rate Application in early 2019. However, there are several complications which make a General Rate Application filing impractical in 2019.

Based on the currently established schedule to close the record in the 2017 GRA, as well as the anticipated timeline for an Order and the process surrounding the subsequent Compliance Application, Hydro anticipates that the final Order establishing rates for Hydro's customers may not be in effect until the fall of 2019. If Hydro were to prepare its next GRA before the final Order is issued from the 2017 GRA, the filing would not be reflective of its 2017 GRA final rates. Hydro would have to refile its application soon after the 2017 GRA final rates became effective to adjust for the impact of the expected customer rates. This would cause a duplication of regulatory effort on the part of Hydro, the Board, and any parties to Hydro's GRA.

Processes are currently underway regarding the Cost of Service Methodology Review, filed in November 2018, and the Rate Mitigation Reference. The Cost of Service Methodology Review proposes changes to the Cost of Service Methodology for use in the determination of test year class revenue requirements specifically reflecting the inclusion of the Muskrat Falls Project costs. This will directly impact the next GRA. Hydro will need time to reflect the approved Cost of Service Methodology in its next GRA filing.

A public hearing is scheduled for October/November 2019 for the Rate Mitigation Reference, with the final report from the Board due in January 2020. Because the outcome of the Rate Mitigation Reference will be a report to the Government of Newfoundland and Labrador, it can be assumed that the Government will need time to review the report and determine what rate mitigation steps will be implemented. It is reasonable to expect that important information or directives regarding rate mitigation would not be available before February/March 2020.

Hydro submits that filing its next GRA prior to incorporating into its filing knowledge and information as to: (i) 2017 GRA rate impacts, (ii) Cost of Service Methodology changes that are specifically reflective of Muskrat Falls Project costs, and (iii) policy determination by the Government following the Rate Mitigation Reference, would almost certainly result in multiple revisions to Hydro's application. The multiple filings would result in regulatory inefficiencies and the costs associated with the conduct of the

GRA would be increased from what they would be otherwise. Ongoing revisions to the proposed rate impacts will also contribute to customer confusion.

Hydro therefore submits that given the uncertainties set out above, the Board should not set a date in this proceeding as to Hydro's next GRA filing. Hydro further submits that the date for such a filing should be set in consultation with the Parties after better information is available and determinations have been made flowing from the aforementioned regulatory proceedings.

D. Conclusion and Order Requested

In conclusion, Hydro seeks an Order under the *Act*, and specifically under Sections 58, 64, 70, 71, 75, 76, 78, and 80, of the *Act,* as follows:[195]

Revenue Requirement

(1) that the Board approve the Settlement Agreement dated April 11, 2018, the Supplemental Settlement Agreement dated July 16, 2018 (Supplemental Settlement Agreement), and the Labrador Settlement Agreement dated August 24, 2018;

(2) that Hydro's proposal to have its 2018 and 2019 Test Year revenue requirements, and resulting rates, reflect the cost of the expected supply of power to the Island Interconnected System from both off-island power purchases and existing Island generation as described in the Additional Cost of Service Information filed in compliance with Board Order No. P.U. 2(2018) and agreed to in section 14 of the Supplemental Settlement Agreement dated July 16, 2018;

(3) that a revised definition to the Energy Supply Cost Variance Deferral Account to include variances in both price and volume of off-island power purchases, as originally provided in Appendix L of the Additional Cost of Service Evidence filed on March 22, 2018 in compliance with Board Order No. P.U. 2(2018); agreed to in section 18 of the Supplemental Settlement Agreement dated July 16, 2018, to be approved, effective January 1, 2019; and updated in Appendix I of Hydro's filing of November 14, 2018;

[195] This requested relief differs in some respects from that filed with the Board as Appendix H of Hydro's "2018 Cost Deferral and Interim Rates Evidence," Revision 2, November 14, 2018, (which was confirmed in PUB-NLH-185 to be the matters upon which Hydro is seeking approval).

(4) that the inclusion of variances in net savings from forecast 2018 off-island power purchases reflected in Hydro's 2018 Revenue Deficiency be approved;

(5) that for the purposes of calculating Hydro's 2018 Test Year, subject to change following the Board's final order and Hydro's Compliance Application:

a) an estimated 2018 Test Year revenue requirement of $578,650,604 be approved;

b) an estimated 2018 forecast average rate base of $2,244,455,753 be approved; and

c) an estimated rate of return on rate base of 5.45% in a range of 5.25% to 5.65%, be approved;

(6) that for the purposes of calculating Hydro's 2019 Test Year, subject to change following the Board's final order Hydro's Compliance Application:

a) An estimated 2019 Test Year revenue requirement of $591,852,326 be approved;

b) an estimated 2019 forecast average rate base of $2,335,231,298 be approved; and

c) an estimated rate of return on rate base of 5.45% in a range of 5.25% to 5.65%, be approved;

(7) a) that Hydro's forecast capital structure for 2018, as set out in Chapter 4 of the evidence in support of this Application, with an estimated weighted average cost of capital of 5.45%, to be updated in Hydro's Compliance Application, 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 an estimated weighted average cost of capital of 5.45%, to be updated in Hydro's Compliance Application, be approved;

(8) 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. 2(2019) as a result of Newfoundland Power's general rate application, of 8.5%, be approved;

(9) that the Holyrood conversion rate of 583 kWh per barrel for the 2019 Test Year, as agreed to in Section 16 of the Supplemental Settlement Agreement dated July 16, 2018, be approved;

(10) that Hydro's revenue requirement include the updated costs associated with Capacity Assistance agreements for 2018 and 2019, as updated in Hydro's October 26, 2018 filing, referenced in Section 22 of the Supplemental Settlement Agreement dated July 16, 2018, be approved;

(11) that Hydro's revenue requirements reflecting vacancies in full time equivalents of 55, as agreed to in Section 10 of the Settlement Agreement dated April 11, 2018, be approved;

(12) that Hydro's costs and expenses related to the Business Systems Transformation Project described in the Application be deferred in a separate account with recovery subject to a further order of the Board, as agreed to in Section 11 of the Settlement Agreement dated April 11, 2018, be approved;

(13) that the Debt Guarantee Fee be included in Hydro's revenue requirement in accordance with Section 12 of the Settlement Agreement dated April 11, 2018, be approved;

(14) that Hydro's 2018 Test Year fuel expense and power purchase expense reflect the 2015 Test Year inputs for the operation of: the Rate Stabilization Plan, Energy Supply Cost Variance Deferral Account, Holyrood Conversion Rate Deferral Account, and the Isolated Systems Cost Variance Deferral account including: (i) a No. 6 fuel cost of $64.41 per barrel, (ii) a conversion rate of 618 kWh per barrel, and (iii) the 2018 Test Year load for use in the Rate Stabilization Plan, be approved;

Regulatory Accounting

(15) that Hydro's continued use of the working capital methodology, as agreed to in Section 14 of the Settlement Agreement dated April 11, 2018, be approved;

(16) that Hydro's proposed average rate base methodology, as agreed to in Section 13 of the Settlement Agreement dated April 11, 2018, be approved;

(17) that Hydro's proposed depreciation rates and methodology, as agreed to in Section 9 of the Settlement Agreement dated April 11, 2018 and Section 7 of the Labrador Settlement Agreement, be approved;

(18) that Hydro's proposal in relation to an automatic adjustment mechanism for its target return on equity to reflect any changes to Newfoundland Power's approved target return on equity for rate setting, as agreed to in Section 24 of the Settlement Agreement dated April 11, 2018, be approved;

(19) that Hydro's proposal to amortize and recover general rate and cost of service hearing costs over a three year period commencing in 2018, as agreed to in Section 22 of the Settlement Agreement dated April 11, 2018, be approved;

(20) that, for Newfoundland Power, Island Industrial and Hydro Rural Government Diesel customers, Hydro's proposal to recover its 2018 and 2019 revenue deficiencies or revenue excesses over a 20-month period commencing on the dates 2017 GRA final rates are implemented, consistent with Sections 20 and 21 of the Supplemental Settlement Agreement dated July 16, 2018, be approved;

(21) that, for customers on the Labrador interconnected system, Hydro's proposal to recover its 2018 and 2019 revenue deficiencies or revenue excesses over a 24-month period commencing on the dates 2017 GRA final rates are implemented, consistent with Section 9 of the Labrador Settlement Agreement dated August 24, 2018, be approved;

(22) that Hydro's proposal to include its 2018 and 2019 revenue deficiency or revenue excesses in rate base, as set out in Chapter 4 of the evidence in support of this Application, be approved;

(23) that Hydro's proposal to include 2015, 2016, and 2017 deferred supply costs of approximately $65.4 million in rate base, be approved;

(24) that the No. 6 fuel price used in the calculation of the 2018 and 2019 Test Year fuel inventory for rate base, reflecting the approved test year fuel cost per barrel, be approved;

(25) that Hydro's excess earnings account definition, as agreed to in Section 23 of the Settlement Agreement dated April 11, 2018, be approved;

(26) that Hydro's proposed accounting treatment and methodology for calculation of Employee Future Benefits in the 2018 and 2019 Test Years, as agreed to in Section 7 of the Settlement Agreement dated April 11, 2018, be approved;

(27) that Hydro's proposed accounting treatment and calculation of Asset Retirement Obligations in the 2018 and 2019 Test Years, as agreed to in Section 8 of the Settlement Agreement dated April 11, 2018, be approved;

(28) that the MF-HVY Capital Project will be:

a) excluded in Hydro's rate base in the 2018 Test Year and excluded in the calculation of depreciation expense for the 2018 Test Year;

b) included in Hydro's closing rate base for the 2019 Test Year, if the project approved by the Board, prior to Hydro's 2017 GRA Compliance filing, for construction to be completed by the end of 2019;

c) excluded for the calculation of depreciation for the 2019 test Year;

Cost of Service Methodology

(29) 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), and as agreed to in Section 8 of the Supplemental Settlement Agreement dated July 16, 2018, be approved to continue on a pilot basis;

(30) 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, and as per Hydro's report dated December 21, 2017, as agreed to in Section 15 of the Settlement Agreement dated April 11, 2018 and section 7(c) of Supplemental Settlement Agreement dated July 16, 2018, be approved;

(31) that wind energy purchases classified as 100% energy-related, as agreed to in Section 7(a) of the Supplemental Settlement Agreement dated July 16, 2018, be approved;

(32) that the functionalization of TL 267 as 100% demand, as agreed to in Section 7(d) of the Supplemental Settlement Agreement dated July 16, 2018, be approved;

(33) that the revenue requirement method to allocate the rural deficit between Newfoundland Power and the Labrador Interconnected system approved by Order No.P.U. 49 (2016), as agreed to in Section 16 of the Settlement Agreement dated April 11, 2018, for use in the 2018 and 2019 Test Years, be approved;

(34) that a filing date of no later than November 15, 2018 for Hydro's Cost of Service and Rate Design Methodology Review, as agreed to in the Section 25 of the Settlement Agreement dated April 11, 2018, be approved;

2019 Rate Proposals

(35) that, effective July 1, 2019, rates reflecting the 2017 GRA Order for all of Hydro's customers be approved on a final basis;

(36) that, effective July 1, 2019, Newfoundland Power's rates, as agreed to in Section 9 of the Supplemental Settlement Agreement dated July 16, 2018, be approved as follows:

a) Newfoundland Power's demand charge will equal $5.00 per kW of billing demand;

b) The size of Newfoundland Power's first block energy component will be determined in consultation with Newfoundland Power prior to the filing of Hydro's 2017 GRA Compliance filing;

c) Newfoundland Power's approved 2019 Test Year revenue requirement not recovered through the demand charge and the end-block energy charge will be used to compute the first block energy charge;

d) Newfoundland Power's end-block firm energy rate for use in Hydro's 2017 GRA Compliance filing will be determined based on the most current fuel rider forecast (either March or September) divided by the approved 2019 Test Year Holyrood No.6 fuel conversion rate and expressed on a cent per kWh basis;

e) The wholesale rate will continue to include the Generation Credit and Curtailable Credit in computation of the billing demand of Newfoundland Power; and

f) The Generation Credit will equal 118,054 kW for the 2018 Test Year and the 2019 Test Year;

(37) that, effective July 1, 2019, the RSP fuel rider applicable to Newfoundland Power, as approved in Board Order No. P.U. 15(2018), be discontinued;

(38) that for Newfoundland Power an additional 2017 GRA Recovery rider to become effective July 1, 2019 and remain in effect for 20 months to recover or refund the forecast 2018 and 2019 revenue deficiencies or revenue excess, consistent with Section 20 of the Supplemental Settlement Agreement dated July 16, 2018, be approved;

(39) that for the Island Industrial Customers an additional 2017 GRA Recovery rate rider to become effective July 1, 2019 and remain in effect for 20 months to recover or refund the forecast 2018 and 2019 revenue deficiencies or revenue excess, consistent with Section 20 of the Supplemental Settlement Agreement dated July 16, 2018, be approved;

(40) that the 2017 GRA recovery rider for the Island Industrial Customers forecast 2018 and 2019 revenue deficiencies or revenue excess be tracked by month and any over or under recovery at the conclusion of the 20 month period be charged or credited to the Island Industrial Customer’s Rate Stabilization Plan Current Plan account;

(41) that on an interim basis for Island Industrial Customers, effective upon the implementation of revised in 2019 RSP adjustments: (i) a firm demand charge increase

from \$9.95 per kW to \$10.90 per kW and the firm energy charge of 3.521 cents per kW, and (ii) the following specifically assigned charges per year:

Corner Brook Pulp and Paper	\$11,458
North Atlantic Refinery Limited	\$104,051
Teck Resources Limited	\$50,030
Vale	\$144,378

(42) that, effective January 1, 2019, the RSP fuel rider applicable to Island Industrial Customers approved in Board Order P.U. 7(2018), be discontinued;

(43) 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;

(44) that the deferral of consideration of whether information on the rural deficit should be included on customers' bills for inclusion in a separate proceeding or a future Hydro general rate application, as agreed to in Section 20 of the Settlement Agreement dated April 11, 2018, be approved;

(45) that IOC is eligible for a billing credit from Hydro if actual monthly Labrador firm load requirements exceed the 2019 Test Year Load forecast by more than 10 MW. The billing credit will be calculated in accordance with Section 10 of the Labrador Settlement Agreement;

Deferred Supply Costs

(46) that Hydro's deferred supply costs be approved as prudent, specifically:

a) 2015 Isolated Systems Supply Cost Variance Deferral Account balance of \$0.00;
b) 2016 Isolated Systems Supply Cost Variance Deferral Account credit balance of \$2,186,570.00;
c) 2017 Isolated Systems Supply Cost Variance Deferral Account credit balance of \$1,106,821.00;
d) 2015 Energy Supply Cost Variance Deferral Account debit balance of \$14,200,429.00;
e) 2016 Energy Supply Cost Variance Deferral Account debit balance of \$24,462,996.00;
f) 2017 Energy Supply Cost Variance Deferral Account debit balance of \$20,134,732.00;
g) 2015 Holyrood Conversion Rate Deferral Account debit balance of \$3,582,048.00;
h) 2016 Holyrood Conversion Rate Deferral Account debit balance of \$2,150,665.00;

i) 2017 Holyrood Conversion Rate Deferral Account debit balance of $4,163,799.00;

(47) that the allocation of balances from the Isolated Systems Cost Variance Deferral Account based upon the same methodology as that which is approved for the allocation of the Rural Deficit, as agreed to in Section 10 of the Supplemental Settlement Agreement dated July 16, 2018, be approved;

(48) that the Labrador Interconnected System allocated portions of the Isolated Systems Cost Variance Deferral Account Energy Supply Cost Variance Deferral and Holyrood Conversion Rate Deferral Account be written off to Hydro's 2018 net income as agreed to in Section 8 of the Labrador Settlement Agreement;

(49) that the allocation of balances in the Energy Supply Cost Variance Deferral and Holyrood Conversion Rate Deferral Account computed by customer class based upon the fuel cost allocation methodology used in the Rate Stabilization Plan, and the allocation percentage be based upon the energy allocators consistent with the year in which the costs were incurred, as agreed to in Section 12 of the Supplemental Settlement Agreement dated July 16, 2018, be approved;

(50) that balances allocated to Newfoundland Power and the Island Industrial Customers be recovered through rate riders to be determined separately for each customer class and computed reflecting a 20 month recovery period effective July 1, 2019, as agreed to in Section 13 of the Supplemental Settlement Agreement dated July 16, 2018, be approved;

(51) that the recovery rider for the Island Industrial Customers portion of the Energy Supply Cost Variance Deferral and Holyrood Conversion Rate Deferral Account be tracked by month and any over or under recovery at the conclusion of the 20 month period be charged or credited to the Island Industrial Customer's Rate Stabilization Plan Current Plan account;

Rules and Regulations

(52) that the calculation of the Rural Rate Alteration component to use Test Year data, as agreed to in Section 18 of the Settlement Agreement dated April 11, 2018, be approved effective January 1, 2018;

(53) 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, as agreed to in Section 19 of

the Settlement Agreement dated April 11, 2018, be effective the date that new rates from the Application are implemented; and

(54) 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.

(55) that a revision to the RSP rules clarifying that No. 6 fuel cost in Canadian dollars reflect foreign exchange gains and losses, be approved for filing in Hydro's 2017 GRA Compliance Application;

Load Forecast

(56) that Hydro's proposed load forecast for the Island Interconnected Systems for the 2018 and 2019 Test Years, be approved; and

(57) that the 2018 and 2019 Test Year load forecast for the Labrador Interconnected System be updated in Hydro's Compliance Application, in accordance with the Labrador Settlement Agreement, be approved.

ALL OF WHICH IS RESPECTFULLY SUBMITTED on this the 1st day of February, 2019.

Geoffrey P. Young, Q.C. and
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