newfoundland labrador
hydro
a nalcor energy company

Hydro Place. 500 Columbus Drive.
P.O. Box 12400. St. John's. NL
Canada A1B 4K7
t. 709.737.1400 f. 709.737.1800
www.nlh.nl.ca

November 14, 2018

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: 2018 Cost Deferral and Interim Rates Application – Revision 2**

Enclosed with this letter please find one original and thirteen copies of the 2018 Cost Deferral and Interim Rates Application – Revision 2 ("Revised Application").

Subsequent to the filing of the 2018 Cost Deferral and Interim Rates Application on October 26, 2018, ("Original Application") with the Board of Commissioners of Public Utilities ("Board"), Hydro reviewed Order in Council OC2018-213 and concluded that:

i. its Original Application required modification to remove the proposal to transfer operating and maintenance ("O&M") costs for the Labrador-Island Link ("LIL") to the Revised Energy Supply Cost Variance Deferral; and

ii. a specific application regarding the costs related to the LIL and the Labrador Transmission Assets ("LTA"), which is the subject matter of OC2018-213, should be filed separately to provide the most clarity for the Board and other parties. Such application will be filed in due course.

As such, the Revised Application provides for the following:

i. updated interim customer rates for Island Industrial Customers to be implemented in concert with the RSP rate update required for January 1, 2019; and

ii. a proposal for a 2018 Cost Deferral to allow Hydro the opportunity to earn a just and reasonable return in 2018.

A Revised Energy Supply Variance Deferral Account definition has been added to the Revised Application at Schedule 1, Appendix I to reflect that the account will not include any expenditure related to use of the LIL or the LTA under the Interim Transmission Funding Agreements.

This Revised Application does not seek to amend Hydro's 2017 GRA. Rather, it provides updated forecast customer rate impacts and an updated "Part B, Hydro Proposals,"[1] reflecting the most up-to-date off-island power purchases forecast, the settlement agreements, and updated Energy Supply Variance Deferral Account.

Modifications made throughout the application to remove references to the previously proposed O&M deferral are tracked with strike through for ease of review by the Board and parties. Any new wording added for clarity has been highlighted. Some minor typographic errors remaining from the Original Application were also corrected and are indicated with strike through.

If you have any questions, please contact the undersigned.

Yours truly,

***NEWFOUNDLAND AND LABRADOR HYDRO***

SWalsh

Shirley A. Walsh
Senior Legal Counsel – Regulatory
SW/kd

cc: Gerard Hayes – Newfoundland Power
Paul Coxworthy – Stewart McKelvey
Dennis Browne, Q.C. – Brown Fitzgerald Morgan & Avis

ecc: Dean Porter – Poole Althouse
Van Alexopoulos – Iron Ore Company
Senwung Luk – Olthuis Kleer Townshend LLP
Denis J. Fleming – Cox & Palmer
Benoît Pepin – Rio Tinto

[1] Initially provided in Hydro's 2017 General Rate Application.

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

**AND IN THE MATTER OF** a General Rate Application by Newfoundland and Labrador Hydro ("Hydro") filed on July 28, 2017, as revised;

**AND IN THE MATTER OF** an application by Hydro for approval of: ~~(i) deferral of the operating and maintenance ("O&M") costs required to be paid by Hydro for use of the Labrador-Island Link ("LIL") and Labrador Transmission Assets ("LTA") prior to full commissioning of the Muskrat Falls Project;~~
(i~~i~~) a 2018 cost deferral account to provide Hydro the opportunity to earn a reasonable return on rate base in 2018 pursuant to Section 80 of the *Act*; and
(ii~~i~~) an application by Hydro, pursuant to Sections 70 and 75 of the *Act,* for the approval of Island Industrial Customer electricity rates to become effective January 1, 2019 on an interim basis (2018 Cost Deferral and Interim Rates Application).

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

**The 2018 Cost Deferral and Interim Rates Application of Hydro states that:**

**A. Background**

1. Hydro is a corporation continued and existing under the *Hydro Corporation Act*, *2007,* is a public utility within the meaning of the *Act*, and is subject to the provisions of the *Electrical Power Control Act, 1994*.

2. Under the *Act*, the Board has the general supervision of public utilities and requires that a public utility submit for the approval of the Board the rates, tolls, and charges

for the service provided by the public utility and the rules and regulations which relate to that service.

3. Section 70 of the *Act* provides that a public utility shall not charge, demand, collect, or receive compensation for a service performed by it until the Board has approved a schedule of rates, tolls, and charges for the services provided by the public utility.

4. Section 75 of the *Act* provides that the Board may make an interim order unilaterally and without public hearing or notice, approving with or without modification, a schedule of rates, tolls and charges submitted by a public utility upon the terms and conditions that it may decide.

5. Section 80 of the *Act* requires that a public utility be entitled to earn annually a just and reasonable return as determined by the Board on the rate base as fixed and determined by the board for each type or kind of service supplied by the public utility.

6. In Order No. P.U. 49(2016), the Board ordered, amongst other things, that Hydro file its next General Rate Application (GRA) 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 GRA on or before July 31, 2017, reflecting 2018 and 2019 Test Years. The Board provided its approval to Hydro's application in Order No. P.U. 8(2017).

7. On July 28, 2017, Hydro filed its 2017 GRA with the Board requesting approval of a number of proposals. One proposal was a request that the Board approve Hydro's 2018 and 2019 Test Year revenue requirements assuming no access to off-island power purchases and the continued use of thermal generation from the Holyrood Thermal Generation Station. This 2017 GRA proposal also requested that any savings resulting from access to off-island purchases be set aside in the Off-Island Purchases Deferral Account (the Deferral Account Scenario).

8. In Order No. P.U. 2(2018), the Board required Hydro to file forecast 2018 and 2019 revenue requirements and cost of service studies including the expected supply of off-island purchases, setting out the basis and support for the forecasts and assumptions used and including information related to customer rates and the updated fuel price forecast (Expected Supply Scenario).

9. Hydro provided a report on March 22, 2018 entitled "Summary Report – Additional Cost of Service Information" providing the requested information on the Expected Supply Scenario. This report provided a summary of the cost of service, revenue deficiencies and customer rates impacts using both the Deferral Account Scenario (using an updated fuel forecast) and the Expected Supply Scenario. The report also identified the changes Hydro is required to make to its deferral mechanisms in order to deal with supply cost uncertainty related to off-island purchases in the 2018 and 2019 Test Years.

10. On April 11, 2018, the Parties entered into a Settlement Agreement (the Settlement Agreement) which, in combination with a Supplemental Settlement Agreement dated July 16, 2018 (the Supplemental Settlement Agreement), resolved a number of 2017 GRA matters. The Supplemental Settlement Agreement confirmed the Parties' agreement to the use of the Expected Supply Scenario in determining Hydro's supply costs for each test year, and the use of the Revised Energy Supply Cost Variance Deferral Account to defer cost variances from the off-island purchase cost projections in the 2018 and 2019 Test Years. The definition of the Revised Energy Supply Cost Variance Deferral Account was accepted in the July 16, 2018 Supplemental Settlement Agreement.

11. A third settlement agreement on revenue requirement issues specific to the Labrador Interconnected System was filed with the Board on August 24, 2018 (the Labrador Settlement Agreement).

**B. LIL and LTA Operating and Maintenance Costs**

12. On July 20, 2018, Hydro filed supplemental evidence providing the customer impacts of the Settlement Agreement, Supplemental Settlement Agreement and the Labrador Settlement Agreements (the 2017 GRA Settlement Agreements). The supplemental evidence assumed that the O&M costs Hydro would incur for the use of the LIL and LTA to permit off-island purchases would be recovered through 2017 GRA customer rates to become effective in 2019.

13. On August 31, 2018, Hydro submitted an information filing on its interim Transmission Funding Agreements (interim TFAs) with the Labrador-Island Link Limited Partnership and Labrador Transmission Corporation (the asset owners of LIL and LTA). The interim TFAs require Hydro to reimburse the asset owners for their actual O&M costs which arise as a result of the assets being made available for service earlier than would otherwise be required (i.e., the LIL monopole commissioning date). The LIL monopole commissioning date is the date upon which Hydro is required to begin paying the O&M costs for the LIL and LTA under the interim TFAs.

14. Hydro entered into the interim TFAs to enable it to use the LIL and LTA to reduce costs for customers of the Island Interconnected System.

15. In addition, Nalcor Energy has provided a Minimum Performance Guarantee to Hydro that ensures that the savings realized by Hydro's use of off-island purchases will be adequate to offset any costs incurred by Hydro under the interim TFAs. Under the terms of the Minimum Performance Guarantee, Nalcor Energy will provide compensation to Hydro in the event that Hydro does not realize Net Savings as a result of entering into the interim TFAs. The Minimum Performance Guarantee was also filed with the Board on August 31, 2018.

16. The July 20, 2018 supplemental evidence stated that the basis for the 2018 and 2019 Test Year supply costs reflected a material increase in off-island purchases over the LIL beginning October 1, 2018, and a monopole commissioning date for the LIL in late October 2018.

17. On August 27, 2018, Hydro informed the Board by letter that, due to HVdc control equipment software issues, the LIL monopole commissioning date had to be revised. Hydro committed to providing updated customer rate projections at a later date.

18. In its October 1, 2018 LIL In-Service Biweekly Update, Hydro informed the Board that Hydro is taking a more conservative outlook regarding the LIL availability for 2018 and 2019. Hydro is now projecting that the LIL will be capable of transferring 110 MW at a forced outage rate of 30% for 2019.

19. ~~Due to the ongoing uncertainty regarding the availability of reliable supply over the LIL,~~ In accordance with OC2018-213, Hydro ~~proposes to~~ has ~~exclude~~ excluded the O&M costs for the LIL and LTA from its 2018 and 2019 Test Year revenue requirements. However, as Hydro will be required to pay these costs beginning on the LIL monopole commissioning date, for the use of the LIL and LTA to provide supply cost savings to customers, Hydro will file a further Application ~~proposes~~ proposing to defer ~~transfer to the Revised Energy Supply Cost Variance Deferral Account~~ all LIL and LTA ~~O&M~~ costs paid by Hydro. The proposed ~~transfer~~ deferral

will occur for the period beginning with the monopole commissioning date and concluding upon full commissioning of the Muskrat Falls Project.

20. The ~~recovery of the balance in the~~ Revised Energy Supply Cost Variance Deferral Account ~~is subject to a further order of the Board~~, originally included in Hydro's March 22, 2018 filing in compliance with Order No. P.U. 2(2018), has been amended to clearly indicate that the O&M Costs for the LIL and the LTA will not be charged to this account. The Revised Energy Supply Cost Variance Deferral Account is attached as Appendix I to Schedule 1.

21. Order No. P.U. 40(2003) sets out the manner by which the Rate Stabilization Plan (RSP) is calculated and applied to the rates that Hydro charges its Island Industrial Customers and Newfoundland Power. The most recent version of the RSP rules was approved in Order No. P.U. 15(2018).

22. The RSP rules require that by the 10th working day in October, Hydro shall provide to the Board, its Industrial Customers, and to Newfoundland Power an estimate of the Industrial Customer fuel rider that will become effective January 1 of the coming year. On October 15, 2018, Hydro provided the Board with its updated No. 6 fuel price forecast for the 2019 calendar year of $92.50 per barrel, as well as the projected fuel rider.

23. On October 2, 2018, the Board directed that Hydro file, by October 26, 2018, an update reflecting both the revised forecast of off-island purchases and the updated fuel price forecast along with the revised customer rate projections for 2019 for each customer class. The Board also directed Hydro to file a revision to its 2017 GRA to update Part B, Hydro Proposals.

24. Schedule 1 to this 2018 Cost Deferral and Interim Rates Application provides evidence on Hydro's projected customer rates reflecting the proposal to defer the LIL and LTA O&M costs during the pre-commissioning period for the Muskrat Falls Project, in accordance with OC2018-213. The Schedule also reflects Hydro's current forecast of off-island purchases (as detailed in Hydro's correspondence to the Board in the October 1, 2018 LIL In-Service Biweekly Update). The 2019 Test Year revenue requirements provided in Schedule 1 are based on the updated No. 6 fuel price forecast of $92.50 per barrel and the 2017 GRA Settlement Agreements. Hydro has also updated its diesel and gas turbine fuel price forecast reflecting the September 2018 forecast for 2019 provided by PIRA.

25. In compliance with the Board's direction in its October 2, 2018 letter, Appendix H to Schedule 1 provides an update to Hydro's 2017 GRA Part B, Hydro Proposals reflecting the updated projected customer rates and test year revenue requirements.

**C. Island Industrial Interim Rates**

26. On February 9, 2018, Hydro filed an application for approval of a number of matters, including a proposed interim Island Industrial customer rates to become effective April 1, 2018. The basis for Hydro's interim rates application was to provide Hydro an opportunity to earn a just and reasonable return during 2018.

27. The interim rates application proposed an average interim rate increase of 1.2% for Island Industrial Customers, with increases for individual customers ranging from 0.6% to 3.0%. The proposed changes included: i) interim base rates; ii) an updated RSP Fuel Rider; and iii) an updated RSP Current Plan Adjustment. The proposed interim base rates reflected an increase in the demand charge, no change in the base firm energy charge, and no changes to the specifically assigned charges. The proposed RSP rates reflected the continued operation of the RSP relative to the 2015 Test Year with a new RSP Fuel Rider to reflect the No. 6 fuel price projection for 2018, and a new RSP Current Plan Adjustment.

28. In Order No. P.U. 7(2018), the Board approved the proposed Island Industrial Customers rates on an interim basis effective April 1, 2018. The Board also ordered that Hydro establish a deferral account to track 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 was

approved. This tracking was ordered for each Island Industrial Customer beginning on April 1, 2018.

29. The sale of the frequency converter to Corner Brook Pulp and Paper (CBPP) was approved by the Board in Order No P.U. 26(2018). The transfer of this asset to CBPP is reflected in the projected customer rates provided in Schedule 1 to this 2018 Cost Deferral and Interim Rates Application.

30. Section D. 2. of the RSP rules requires an update to the Industrial Customer RSP Current Plan Adjustment to become effective January 1 of each year to recover the balance in the Industrial Customer RSP balance at December 31 of the previous year, and the forecast financing charges to the end of the following calendar year.

31. The Industrial Customer RSP Current Plan Adjustment is currently (0.285) cents per kWh. The existing Industrial Customer RSP Current Plan Adjustment reduces customer rates as a result of a credit balance owed to customers at December 31, 2017.

32. Hydro is projecting an Industrial Customer RSP Current Plan balance owing from Industrial Customers of approximately $1.9 million (including financing) at year-end 2018. This would require a RSP Current Plan adjustment of 0.312 cents per kWh. The 2019 Industrial Customer RSP Current Plan Adjustment update will require an

increased collection of approximately $4.4 million in 2019 relative to 2018, which equates to an approximate 11.2% average customer rate increase. Schedule 1 provides the calculation of the projected RSP Current Plan Adjustment to become effective January 1, 2019.

33. The projected 2019 Test Year base rate revenue requirement for Island Industrial Customers, as provided in Schedule 1, is approximately $2.2 million less than the forecast 2019 revenue under existing interim rates (i.e., providing a 5.7% savings to offset the projected RSP increase). This calculation excludes the impact of the change in the specifically assigned charge methodology, which is being tracked in a deferral account.

34. The proposed change in the specifically assigned charge methodology has been accepted by the Parties to the Supplemental Settlement Agreement. Therefore, Hydro believes it is reasonable to also reflect this change in the proposed January 1, 2019 interim rates. The change in the specifically assigned charge methodology further reduces the projected 2019 Test Year base rate revenue requirement by approximately $460,000 (i.e., an additional 1.2% savings to offset the projected RSP increase).

35. Board approval of the proposed deferral of the LIL and LTA ~~O&M~~ costs, in accordance with OC2018-213, is also reflected in the projected test year revenue

requirements presented in Schedule 1. Assuming this approval, Hydro proposes to reduce Island Industrial Customer base rates at the same time that the RSP Current Plan Adjustment is implemented.

36. The proposed Industrial Customer rates to become effective January 1, 2019 would not include an RSP fuel rider because the new 2019 forecast No. 6 fuel price of $92.50 is reflected in the projected 2019 base rate revenue requirements provided in Schedule 1.

37. On an interim basis, Hydro proposes to (i) update the firm demand charge and the firm energy charge based on the 2019 Test Year Cost of Service Study provided in Appendix D to Schedule 1 and (ii) to revise the specifically assigned charges to reflect the specifically assigned charge methodology accepted in the Supplemental Settlement Agreement. Hydro proposes to implement these rate changes at the same time as the implementation of the updated RSP Current Plan Adjustment rate and the elimination of the RSP fuel rider, which is expected to be January 1, 2019.

38. Hydro proposes to file its revised rate sheet reflecting both the base rate change and the RSP rate changes through the RSP update application to be filed in January 2019.

39. The projected customer rate impacts for Island Industrial Customers reflecting the projected RSP Current Plan Adjustment rate and the proposed interim base rates are provided in Appendix F to Schedule 1.

**D. Proposed 2018 Cost Deferral**

40. The duration of the GRA process has been impacted by the uncertainty in the forecast supply costs to be used in establishing customer rates during the pre-commissioning period of the Muskrat Falls Project. Given the 2017 GRA process is not yet completed, Hydro anticipates that the 2017 GRA Order will not be issued until 2019.

41. In the absence of a 2017 GRA Order in 2018, Hydro's forecast 2018 net income is $9.9 million. This equates to a 3.13% rate of return on equity and a 4.63% return on rate base in 2018. The projected range of rate of return on rate base for the 2018 Test Year is 5.25% - 5.65% which has been derived by applying the 8.5% rate of return on equity pursuant to Order in Council OC2009-063. A rate of return on rate base of 4.63% for 2018 is below the lower end of the projected range of rate of return on rate base for 2018 to be used in the 2017 GRA Compliance Application.

42. The Settlement Agreement included a revised approach to Hydro's depreciation methodology which would become effective for the 2018 Test Year upon issuance of the final 2017 GRA Order. If there is no 2017 GRA Order in 2018, the use of the

current depreciation methodology will be required. Hydro's projected 2018 depreciation cost (including depreciation, loss on disposal, disposal proceeds, and removal costs) is projected to increase by $15.0 million compared to the projected 2018 depreciation cost using the depreciation methodology accepted in the Settlement Agreement. Schedule 2 provides Hydro's evidence providing the forecast financial impacts of the GRA Order being delayed until 2019.

43. Hydro proposes that the Board approve a 2018 Cost Deferral Account definition which will permit Hydro to defer for 2018 the depreciation expense differential between Hydro's current depreciation expense methodology and the 2017 GRA depreciation methodology.

44. Schedule 3 to this 2018 Cost Deferral and Interim Rates Application provides the proposed 2018 Cost Deferral Account definition.

45. Approval of the proposed 2018 Cost Deferral will provide Hydro the opportunity to earn a rate of return on rate base for 2018 of 5.28% that is within the projected range of rate of return referenced above. This is an interim measure to allow Hydro to earn a just and reasonable return while the finalization of the GRA is pending. The finalization of the return on rate base will be made by the Board pursuant to OC2009-063 at the conclusion of the 2017 GRA.

46. Hydro notes that the depreciation methodology is a settled item and the cost is prudently incurred in serving customers.

**E. Application Requests**

47. Therefore, Hydro requests that the Board make an Order approving:

~~(a) the transfer to the Revised Energy Supply Variance Deferral Account of all 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 TFAs and the Minimum Performance Guarantee, less any compensation provided by Nalcor pursuant to the Minimum Performance Guarantee;~~

(a) revised base rates on an interim basis, effective upon the implementation of revised RSP adjustments providing: (i) an increase in firm demand charge from $9.95 per kW to $10.90 per kW and a decrease in the firm energy charge from 3.971 cents per kWh to 3.521 cents per kWh; 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 |

(b) a 2018 Cost Deferral Account Definition, as provided in Schedule 3 to this 2018 Cost Deferral and Interim Rates Application, providing for Hydro to defer the 2018 depreciation expense differential between Hydro's current depreciation expense methodology and the 2017 GRA depreciation methodology provided for in the Settlement Agreement.

**DATED AT** St. John's in the Province of Newfoundland and Labrador this 14th day of November, 2018.

**NEWFOUNDLAND AND LABRADOR HYDRO**

Shirley A. Walsh
Counsel for the Applicant
Newfoundland and Labrador Hydro
500 Columbus Drive, P.O. Box 12400
St. John's, NL A1B 4K7
Telephone: (709) 737-1365
Facsimile: (709) 737-1782

# ~~2018 Cost Deferral~~ Evidence on Customer Rates

October 26, 2018
Revised November 14, 2018

*A Report to the Board of Commissioners of Public Utilities*

newfoundland labrador hydro
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## Table of Contents

## 1.0 Background

On July 20, 2018, Hydro filed supplemental evidence[1] providing projected customer rate impacts for 2019. The evidence reflected, among other things, the impacts of the April 11, 2018 Settlement Agreement (the "Settlement Agreement") and the July 16, 2018 Supplemental Settlement Agreement (the "Supplemental Settlement Agreement"), in which the Parties' agreed that customer rates should be set based on the Expected Supply Scenario. On August 27, 2018, Hydro filed a letter with the Board of Commissioners of Public Utilities (the "Board") advising that, due to HVdc control equipment software issues, the Labrador-Island Link (LIL) commissioning date required revision. Hydro committed to providing an update in customer rate projections at a later date.

The basis for the 2018 and 2019 Test Year supply costs reflected in the July 20, 2018 supplemental evidence assumed a material ramp-up in off-island purchases over the LIL beginning October 1, 2018 and a monopole commissioning date for the LIL in late October 2018. The LIL monopole commissioning date is the date upon which Hydro would be required to begin paying the operating and maintenance (O&M) costs for the LIL and the Labrador Transmission Assets (LTA).

On September 5, 2018, the Government of Newfoundland and Labrador released Terms of Reference for the Board to examine options to mitigate the costs of the Muskrat Falls Project. The Board has been asked to deliver an interim report by February 15, 2019 and a final report by January 31, 2020. The results of the rate mitigation activities, including the impacts of revenue generation activities through exports, may have a material impact on the Muskrat Falls Project supply costs to be recovered through customer rates.

On October 2, 2018, the Board directed that Hydro file, by October 26, 2018, an update reflecting both the revised forecast of off-island purchases and the updated fuel price forecast,

[1] Revised on August 3, 2018.

along with the revised customer rate projections for 2019 for each customer class. The Board also directed Hydro to file a revision to its general rate application (GRA) to update Part B, Hydro Proposals. The Board also indicated that if revised interim customer rates are required, then this filing should include an interim rates application.

This evidence provides the required update directed by the Board and an interim rates application for Island Industrial Customers. Hydro is not seeking interim rate changes for its other customer classes.

## 2.0 Summary of Revisions

This section provides a summary of the revised assumptions used in preparing the updated customer rate impacts. Hydro notes that these customer rate projections are estimates. In its 2017 GRA Compliance application, which is filed subsequent to the 2017 GRA Order, Hydro will file updated 2018 and 2019 Test Year revenue requirements, cost of service studies, and proposed rates to reflect the impact of the Settlement Agreement, Supplemental Settlement Agreement, Labrador Settlement Agreement (collectively the 2017 GRA Settlement Agreements), and the direction to be provided by the Board in the 2017 GRA Order.

### 2.1 Availability of Off-Island Purchases Over the LIL

Hydro has assumed a material increase in off-island purchases over the LIL beginning December 1, 2018 and a monopole commissioning date for the LIL of January 1, 2019 (assuming available supply of 110 MW with a 30% forced outage rate for 2019).

### 2.2 Proposed Deferral of LIL/LTA Operating and Maintenance Costs

~~Due to the ongoing uncertainty related to availability of reliable supply over the LIL~~ In accordance with OC2018-213 Hydro ~~is proposing to exclude~~ has excluded the O&M costs for the LIL and LTA from its 2018 and 2019 Test Year revenue requirements. However, Hydro will be required to pay these costs beginning on the LIL monopole commissioning date in order to facilitate fuel savings for its customers. ~~Therefore,~~ Hydro ~~is proposing~~ will propose, in a future application, to ~~transfer~~ defer all costs that it is required to pay for the use of LIL and LTA, during the period prior to full commissioning of the Muskrat Falls Project.~~, to the Revised Energy Supply Variance Deferral Account.~~~~[2]~~

Under the proposed approach, the recovery of the deferred LIL and LTA ~~O&M~~ costs will be subject to a further order of the Board.

### 2.3 Timing of 2019 GRA Final Rate Implementation

As a result on the ongoing delay in completing the 2017 GRA, it is unlikely that a final 2017 GRA Order will be released in 2018. Therefore, Hydro believes it is probable that final rates resulting from the 2017 GRA will not become effective until July 1, 2019. Hydro has continued to assume the amortization periods for recovery of revenue deficiency due to delayed rate implementation as detailed in the GRA Settlement Agreements. However, the projected revenue deficiency now includes amounts for both 2018 and 2019.

### 2.4 2019 Test Year Fuel Price

The 2019 Test Year revenue requirement is based on an updated No. 6 fuel price forecast of $92.50[3] per barrel compared to the $85.55 per barrel used in the July 20, 2018 Supplemental Evidence. Hydro has also updated its diesel and gas turbine fuel price forecast to reflect the September 2018 forecast for fuel price in 2019.

### 2.5 Corner Brook Pulp and Paper (CBPP) Frequency Converter

Hydro has reflected the sale of the frequency converter to CBPP, effective August 9, 2018, in the projected 2018 and 2019 Test Year revenue requirements and the proposed specifically assigned charge for CBPP for 2019.

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~~[2] Proposed Revised Energy Supply Cost Variance Deferral Account definition was filed in Appendix L of Hydro's March 22, 2018 Additional Cost of Service Information filing. The Parties agreed to the implementation of the proposed definition in the Supplemental Settlement Agreement.~~

[3] As filed with the Board on October 15, 2018.

### 2.6 Labrador Revenue and Supply Cost Forecast

Hydro has updated its 2018 Test Year and 2019 Test Year load and supply cost forecasts to reflect the August 24, 2018 Labrador Settlement Agreement. This update reflects current data centre load projections for 2018 and 2019, including both the forecast revenue from higher sales and forecast increase in supply costs (i.e., $220,000 in interruptible costs for the winter of 2018-2019), and an update in the forecast 2019 Power on Order requirements for Labrador Industrial Customers.

Due to the ongoing uncertainty with respect to the Tacora load requirements for 2019, the load forecast for 2019 assumes only 1 MW of ongoing demand requirement for the Wabush Mines facility. However, the Labrador Settlement Agreement also provides for a billing credit to be made to the Iron Ore Company of Canada (IOC) in 2019 in the event that Tacora load requirements are materially higher than indicated in the updated 2017 GRA forecast.

### 2.7 Island Interconnected Capacity Assistance Update

Hydro has updated its capacity assistance cost forecast for 2019 to reflect the additional capacity assistance agreements currently being negotiated for the 2018/2019 winter season. Relative to the July 20, 2018 Supplemental Evidence, this evidence includes an additional 15 MW of capacity assistance from CBPP,[4] 7.6 MW of capacity assistance from Vale and 6 MW of curtailable load from Vale. The additional capacity assistance is required due to the uncertainty of the capacity that will be available over the LIL and is forecast to have the same cost per kW as the previous agreements with CBPP and Vale.

### 2.8 Interim Rates Proposal for Island Industrial Customers

To manage customer impacts resulting from the update to the Rate Stabilization Plan (RSP) Current Plan Adjustment for 2019, Hydro is proposing to reduce Island Industrial Customer base rates at the same time that the RSP Current Plan Adjustment is implemented. The proposed

[4] For a total of 105 MW.

reduction in base rates reflects the material reduction in the forecast base rate revenue requirement from Island Industrial Customers that results from Hydro's proposal to defer recovery of LIL and LTA O&M costs.

In setting Island Industrial Customers interim rates for 2019, Hydro is also proposing to implement, on an interim basis, the proposed change in the methodology of allocation of O&M costs to specifically assigned assets. The proposed methodology change was accepted in the Supplemental Settlement Agreement.

## 3.0 Off-Island Purchases

### 3.1 General

This section provides an updated forecast of savings from off-island purchases for 2018 and 2019. Under the Expected Supply Scenario, the net savings from off-island purchases will be used to reduce the revenue requirements from customers on the Island Interconnected System for the 2018 and 2019 Test Years. In this evidence, off-island purchases include recapture deliveries as well as other off-island purchases but exclude the LIL and LTA ~~O&M~~ costs. Other off-island purchases include short-term economic purchases, such as those which have occurred year-to-date over the Maritime Link.

### 3.2 Off-Island Purchases Forecast

Table 1 provides Hydro's projection of off-island purchases for 2018 and 2019.

**Table 1: Expected Supply from Off-Island Purchases (GWh)[5]**

| Supply Source | 2018 | 2019 |
|---|---|---|
| Recapture Energy | 69 | 667 |
| Other Off-Island Purchases | 83 | 49 |
| **Total** | **152** | **716** |

[5] Assumed delivery to the Island Interconnected System at Bottom Brook for purchases over the Maritime Link and at Soldier's Pond for purchases over the LIL.

Table 2 provides Hydro's projected costs associated with off-island purchases to be recovered from customer rates for 2018 and 2019.

**Table 2: Projected Cost of Supply from Off-Island Purchases ($000s)**

| Supply Source | 2018 | 2019 |
|---|---|---|
| Recapture Energy[6] | 219 | 1,537 |
| Other Off-Island Purchases | 7,316 | 4,582 |
| LIL and LTA O&M Costs | 0 | 0 |
| **Total** | 7,535 | 6,119 |

### 3.3 Savings from Off-Island Purchases

Under the Expected Supply Scenario, forecast savings from off-island purchases for 2018 and 2019 are used to reduce 2018 and 2019 Test Year revenue requirements. Forecast savings reflect the reduction in No. 6 fuel expense,[7] partially offset by the cost of off-island power purchases.

To access off-island power purchases, Hydro entered into interim Transmission Funding Agreements (interim TFAs) with the owners of the LIL and the LTA which will permit Hydro to use those transmission facilities to transmit energy to the island and require Hydro to pay the ~~O&M~~ costs associated with the use of the transmission lines.[8] Hydro entered these interim TFAs to take advantage of the opportunity to use these assets earlier to reduce costs for customers on the Island Interconnected System. Hydro is proposing, in accordance with OC2018-213, that the ~~O&M~~ costs incurred to use the LIL and the LTA prior to full commissioning of the Muskrat Falls Project be deferred for recovery subject to a future Board Order.

[6] Hydro has a contract in place with CF(L)Co to purchase Recapture Energy at a cost of 0.2 cents per kWh.
[7] No. 6 fuel savings are achieved as a result of reduced fuel consumption at the Holyrood Thermal Generating Station.
[8] On August 31, 2018, Hydro submitted an information filing on its interim TFAs with the owners of the LIL and LTA requiring Hydro to reimburse the asset owners for their actual ~~O&M~~ Costs which arise as a result of these assets being made available for service earlier than would otherwise be required.

Hydro's 2018 and 2019 Test Year costs include supply costs related to the purchase of Recapture Energy and costs incurred to achieve power purchases from other jurisdictions. In its 2017 GRA, Hydro proposed that the RSP operate in 2018 based on the 2015 Test Year[9] and in 2019 based on the 2019 Test Year. Therefore, to be consistent with the operation of the RSP, it is appropriate that Hydro determine its 2018 Test Year revenue requirement for revenue deficiency (or revenue excess) based on 2015 Test Year RSP fuel cost inputs (i.e., with No. 6 fuel costs equal to an average of $64.41 per barrel and a Holyrood conversion factor of 618 kWh per barrel) and 2018 Test Year Load.

Savings from off-island purchases in 2018 are not recorded in the RSP but result in savings to Hydro through the net effect of the reduced fuel cost (based on the approved test year fuel cost) and the additional cost of purchases.

A similar approach is required for on-island gas turbine and diesel fuel costs for the 2018 Test Year. Cost variances from the 2015 Test Year from these supply sources will accumulate in the approved Supply Cost Variance Deferral Accounts.[10] Therefore, in order to avoid duplication of fuel cost recovery through 2018 revenue deficiencies and balances accumulating in the Supply Cost Variance Deferral Accounts, Hydro has based the supply costs for the 2018 Test Year from these sources on the 2015 Test Year inputs for computing revenue deficiency/revenue excess for the 2018 Test Year.

In the Supplemental Settlement Agreement, the Parties agreed that the cost of No. 6 fuel for the 2019 Test Year shall be set based on the most current fuel rider forecast (either March or September) at the time of the 2017 GRA Compliance Filing. The most current fuel rider forecast is $92.50 per barrel.[11] While the $92.50 may not be the fuel forecast used for the 2017 GRA Compliance filing, Hydro has used this fuel price in this evidence to estimate its 2019 Test Year

[9] Hydro's 2018 Test Year RSP reflects fuel price of $64.41/bbl and conversion factor of 618 and 2018 Test Year load.
[10] Energy Supply Cost Variance Deferral Account, Isolated Systems Supply Cost Variance Deferral Account, and the Holyrood Conversion Rate Deferral Account.
[11] Based on September 2018 PIRA fuel forecast filed with the Board on October 15, 2018.

revenue requirement. Hydro has also used a No. 6 fuel price of $92.50 per barrel to calculate the savings from off-island purchases for the 2019 Test Year.[12]

In Appendix A to this evidence, Hydro has projected 2018 Test Year No. 6 fuel savings from off-island purchases to be $18.3 million. Appendix B provides projected 2019 Test Year No. 6 fuel savings which are forecast to be $113.6 million.

Table 3 provides the projected net savings from off-island purchases for the 2018 and 2019 Test Years.

**Table 3: Projected Net Savings from Off-Island Purchases ($000s)**

| **Particulars** | **2018** | **2019** |
|---|---|---|
| No. 6 Fuel Savings | 18,342 | 113,578 |
| Less: Projected Costs of Off-Island Purchases | (7,535) | (6,119) |
| **Net Savings from Off-Island Purchases** | **10,808** | **107,460** |

Hydro has reflected the forecast net savings from off-island purchases in its calculation of the 2018 and 2019 Test Year revenue requirements provided in this evidence.

In Appendix A to this evidence, Hydro has computed projected 2018 Test Year No. 6 fuel costs to be $147.7 million. Projected 2019 Test Year No. 6 fuel costs are expected to be $137.9 million (provided in Appendix B).[13]

---

[12] The Supplemental Settlement Agreement signed on July 16, 2018 also provides for the use of a fuel conversion factor of 583 kWh per barrel.

[13]

| | | |
|---|---|---|
| Holyrood Generation (MWh) | (A) | 868,954 |
| Holyrood Conversion Factor (kWh/bbl) | (B) | 583 |
| No. 6 barrels (bbls) | (C) =(A/B) x 1,000 | 1,490,487 |
| Cost per barrel ($/bbl) | (D) | $92.50 |
| Total ($000s) | (E) = (D x C)/1,000 | $137,870 |

The Supplemental Settlement Agreement also provides for variances in the forecast test year ~~net savings~~ price and volume from off-island purchases to be transferred to a Revised Energy Supply Cost Variance Deferral Account.[14] ~~Hydro is now proposing that the cost of O&M for LIL and LTA be treated as a test year supply cost variance and charged to the Revised Energy Supply Cost Variance Deferral Account.~~ Hydro has attached an updated definition for the Revised Energy Supply Cost Variance Deferral Account included as Appendix I. This updated definition specifically prohibits the inclusion of costs associated with use of the LIL and the LTA under the interim TFAs, as these costs will be held in a separate account for which Hydro will apply in due course. The disposition of the balances that accrue in the Revised Energy Supply Cost Variance Deferral Account are subject to a further order of the Board.

### 3.4 Revenue Requirements

To estimate the impact of the settlement agreements, the revised fuel price forecast and the proposed deferral of LIL and LTA O&M in accordance with OC2018-213, Hydro has reflected these revenue requirement adjustments by updating its 2018 and 2019 Test Year Cost of Service Studies.

## 4.0 Cost of Service Results

### 4.1 General

Hydro has used the cost of service methodology as described in the 2017 GRA Settlement Agreements in preparing preliminary cost of service study results to determine customer rate projections. Appendices C and D to this evidence provide the cost of service summary schedules for the 2018 and 2019 Test Years, respectively.

[14] The Supplemental Settlement Agreement does not define the effective date of the deferral account. To ensure the variance from the forecast Test Year savings from off-island purchases are recovered from customers, Hydro is proposing the Revised Energy Supply Cost Variance Deferral Account become effective January 1, 2018. For 2018, Hydro also proposes that the account balance be calculated based on variances from its 2018 Test Year forecast for off-island purchases valued at the 2015 Test Year cost of No. 6 fuel.

The Expected Supply Scenario requires that the test year cost of service study revenue requirements reflect the projected net savings from off-island purchases shown in Table 3.

Hydro has also updated its 2018 and 2019 GRA forecasts to reflect the Labrador Settlement Agreement. This update reflects current data centre load projections for 2018 and 2019, including both the forecast revenue from higher sales and forecast increased supply costs (i.e., $220,000 in interruptible costs for the winter of 2018-2019), and an update in the forecast 2019 Power on Order requirements for Labrador Industrial Customers.

The cost of service studies also assume the delayed Labrador capital project (i.e., providing the Muskrat Falls to Happy Valley transmission interconnection) will be in service in December 2019. If this project has not been approved at the time of Hydro's filing its 2017 GRA Compliance filing then Hydro will exclude the project in calculating the 2019 Test Year revenue requirement. This is consistent with the Labrador Settlement Agreement.[15]

Hydro has used a 24-month amortization period to provide recovery of the 2018 and 2019 revenue deficiency from the Labrador Industrial Transmission customers and the Hydro Rural Labrador Interconnected customers consistent with the Labrador Settlement Agreement.

Finally, the cost of service studies reflect the transfer of the frequency converter asset to CBPP effective August 9, 2018 with no specifically assigned charge in effect for CBPP from the date of the transfer until the end of calendar 2018.[16]

### 4.2 Revenue Deficiencies

Table 4 provides a derivation of Hydro's revenue deficiencies/revenue excesses for 2018 and

[15] The Labrador Settlement Agreement also assumes no depreciation costs in 2019 related to the Muskrat Falls to Happy Valley transmission project.
[16] The transfer of the frequency converter to CBPP was approved by the Board in Order No. P.U. 26(2018).

2019 based on the Expected Supply Scenario reflecting the settlement agreements.[17] The revenue deficiencies/revenue excesses for 2018 were determined by comparing, on a class basis, the 2018 Test Year revenue requirement to the 2018 Test Year revenue forecast calculated using approved base rates in effect for 2018.[18] The revenue deficiency for 2019 was determined following the same approach; however, base rates forecast to be in effect were used in the calculation for forecast 2019 Test Year revenues.[19]

**Table 4: Projected Test Year Revenue Deficiency/Excess by Customer Class ($ millions)** [20]

| | **2018 Test Year** | | | **2019 Test Year** | | |
|---|---|---|---|---|---|---|
| **Particulars** | **Revenue Forecast**[21] | **Revenue Requirement**[22] | **Revenue Excess/ (Deficiency)** | **Existing Rates**[23] | **Revenue Requirement** | **Revenue Excess/ (Deficiency)** |
| | (a) | (b) | (c)=(a)-(b) | (d) | (e) | (f)=(d)-(e) |
| Newfoundland Power | 441.5 | 450.9 | (9.4) | 450.8 | 459.8 | (9.0) |
| Island Industrial | 41.2 | 39.1 | 2.1 | 39.1 | 39.1 | 0.0 |
| Rural Labrador Interconnected | 21.0 | 20.8 | 0.2 | 22.1 | 21.7 | 0.4 |
| Labrador Industrial Transmission | 4.7 | 4.9 | (0.2) | 4.8 | 5.6 | (0.8) |
| Hydro Rural Government Diesel | 2.1 | 2.1 | 0.0 | 2.1 | 2.4 | (0.3) |

Table 4 shows that, for the 2018 Test Year, Hydro will have a deficiency from Newfoundland Power of $9.4 million and a revenue excess of $2.1 million from Island Industrial Customers.

[17] Revenue deficiency and revenue excess are calculated by using base rates and exclude charges related to RSP and CDM adjustments.
[18] The 2018 revenue forecast is calculated by using the actual approved base rates in effect during 2018 applied to the 2018 Test Year load forecast for each class.
[19] For 2019, existing rates reflect customer rates as of July 1, 2018 for all classes except Island Industrial Customers for which proposed January 1, 2019 interim rates are treated as existing rates.
[20] There is no revenue deficiency shown for Hydro Rural Other as the rural deficit is allocated for recovery from Newfoundland Power and Labrador Interconnected customers.
[21] The 2018 rate revenue forecast is calculated using the base rates in effect during 2018 applied to the 2018 Test Year load forecast. Base rate revenues exclude revenues from RSP and CDM riders.
[22] Revenue amounts after allocation of the Rural Deficit.
[23] Island Industrial Customers reflect January 1, 2019 interim rates.

Hydro will have a 2018 revenue excess of $0.2 million from the Hydro Rural Labrador Interconnected class and a revenue deficiency of $0.2 million from the Labrador Industrial Transmission class. Hydro is not projecting a revenue deficiency or a revenue excess in 2018 for Hydro Rural Government Diesel Customers.

The rate change required for Hydro Rural Labrador Interconnected customers is materially lower than proposed in Hydro's July 20, 2018 filing due to the increased revenues from data centre loads for 2018 and 2019 exceeding the additional supply costs incurred to provide the additional load.

Hydro projects a 2019 Test Year revenue deficiency from Newfoundland Power of $9.0 million. With the implementation of proposed interim rates for Island Industrial customers on January 1, 2019, Island Industrial Customers will have no revenue deficiency/revenue excess for 2019. Hydro also projects a 2019 revenue excess of $0.4 million from the Hydro Rural Labrador Interconnected class, a revenue deficiency of $0.8 million from the Labrador Industrial Transmission class, and a $0.3 million revenue deficiency for Hydro Rural Government Diesel Customers.

In the Supplemental Settlement Agreement, the Parties agreed that the Newfoundland Power credit from the Isolated Systems Deferral Account would be applied to reduce the 2018 Revenue Deficiency to be recovered from Newfoundland Power. For purposes of determining rate increase projections for 2019, Hydro has applied this credit of approximately $3.2 million to reduce the deferred supply costs to be recovered from Newfoundland Power.

## 4.3 Deferred Supply Cost Recovery

The Supplemental Settlement Agreement also provides that the deferred supply costs in the Energy Supply Cost Variance and Holyrood Conversion Rate Deferral Accounts of 2015, 2016 and 2017, as approved by the Board for recovery from customers (Approved Deferred Supply

Costs), will be allocated between customer classes in a manner consistent with the fuel cost allocation methodology used in the RSP.[24]

The Parties agree 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 GRA final rates approved by the Board.

Table 5 provides the allocation of the Deferred Supply Costs to be recovered through the rates of Newfoundland Power and Island Industrial Customers.

**Table 5: Allocation of Deferred Supply Costs ($)**

| Account | Balance | Newfoundland Power | Island Industrial Customers | Labrador Allocation |
|---|---|---|---|---|
| Isolated Systems Deferral[25] | (3,293,391) | (3,150,090) | - | (143,301) |
| Energy Supply Cost Deferral | 58,798,157 | 54,111,891 | 4,510,432 | 175,834 |
| Holyrood Conversion Deferral | 9,896,512 | 9,104,028 | 763,054 | 29,429 |
| **Total** | **65,401,278** | **60,065,830** | **5,273,486** | **61,962**[26] |
| **Allocation Based on Historical Energy**[27] | | 91.8% | 8.1% | 0.1% |

[24] The allocation percentage will be based on the RSP energy allocators consistent with the year in which the Approved Deferred Supply Costs were incurred.
[25] The Isolated Systems Deferral has been allocated based upon the 2015 Test Year rural deficit allocation.
[26] Consistent with the allocation methodology in the RSP, the portion of the costs allocated to Hydro Rural are reallocated between Newfoundland Power and Hydro Rural Interconnected customers on the same basis as the rural deficit. Also consistent with the established RSP methodology, Hydro is proposing that the Labrador Allocation of approximately $62,000 be written off to Hydro's net income.
[27] Deferred Supply Costs from each of 2015, 2016, and 2017 have been allocated based upon actual energy consumption from each respective year. The allocations shown in Table 5 represent the summation of these annual allocations.

The Supplemental Settlement Agreement provides that the 2018 revenue deficiency/revenue excess for Newfoundland Power and Island Industrial customers be disposed of through rate riders over a 20-month period. The same approach was agreed upon for recovery of deferred supply costs. Hydro has also applied this approach for the projected 2019 revenue deficiency/revenue excess. Therefore, for the calculation of the riders to recover the deferred supply costs, a 2017 GRA Cost Recovery Rider was computed for each of Newfoundland Power and the Island Industrial Customers reflecting the total of the deferred supply costs and the 2018 and 2019 revenue deficiency/revenue excess.

Table 6 provides the derivation of the estimated monthly charge to apply to Newfoundland Power to provide recovery through the 2017 GRA Cost Recovery Rider.

**Table 6: Estimated 2017 GRA Cost Recovery Rider – Newfoundland Power ($)**

| Particulars | Deferred Supply Costs | 2018 & 2019 Deficiencies | Monthly Charge |
|---|---|---|---|
| | (a) | (b) | (c) = ((a) + (b)) / 20 |
| Newfoundland Power | 60,065,830 | 14,040,411 | 3,705,312 |

For the Island Industrial Customers, the $5.3 million owing for the deferred supply cost is partially offset by the $2.1 million in 2018 revenue excess. The remaining amount of $3.2 million would result in a 2017 GRA Cost Recovery Rider of 0.256¢ per kWh.[28] Included in its update to Part B, Hydro Proposals, included as Appendix H, is a proposal by Hydro to track the Island Industrial Customer 2017 GRA Recovery Rider by month such that any over or under recovery of this amount be charged or credited to the Island Industrial Customer RSP Current Plan balance at the conclusion of the 20-month amortization period.

[28]

| | | |
|---|---|---|
| Annual 2019 Test Year energy | (A) | = 743,300,000 kWh |
| Average Monthly 2019 Test Year energy | (B) = (A)/12 | = 61,941,667 kWh/month |
| Total amount owing | (C) | = $3,170,016 |
| Monthly amount owing | (D) = (C)/20 | = $158,501 |
| Recovery rider | (E) = (D)/(B)*100 | = 0.256 cents/kWh |

# 5.0 Island Industrial Customer Interim Rates Proposal

## 5.1 RSP Update

### 5.1.1 RSP Current Plan Adjustment

Section D.2 of the RSP rules requires an update to the Industrial Customer RSP Current Plan Adjustment to become effective January 1 of each year to recover the balance in the Industrial Customer RSP balance at December 31 of the previous year and the forecast financing charges to the end of the following calendar year.

Hydro is projecting a RSP Current Plan balance owing from Industrial Customers of approximately $1.8 million at year-end 2018 which would require a RSP Current Plan adjustment of 0.312 cents per kWh.[29] This represents an increase of 0.597 cents per kWh from the existing RSP Current Plan Adjustment of (0.285) cents per kWh. The 2019 RSP Current Plan Adjustment update will require an increased collection of approximately $4.4 million in 2019 relative to 2018 which equates to an approximate 11.2% average customer rate increase. Appendix E provides the calculation of the projected Industrial Customer RSP Current Plan adjustment for 2019.

### 5.1.2 RSP Fuel Rider

In accordance with the RSP rules, on October 15, 2018, Hydro provided the Board with its updated No. 6 fuel price forecast for the 2019 calendar year of $92.50 per barrel. However, Hydro's proposed interim Industrial Customer rates do not include an RSP fuel rider for January 1, 2019 as the forecast No. 6 fuel price of $92.50 is reflected in the proposed interim rates, based upon the projected 2019 Test Year base rate revenue requirements.

[29] $1.9 million amount to be recovered including financing costs in accordance with the RSP Rules.

### 5.2 Test Year Revenue Requirement

The projected 2019 Test Year base rate revenue requirement for Island Industrial Customers of $39.1 million, as provided in Table 4, is approximately $2.7 million less than the forecast 2019 revenue under existing interim rates approved April 1, 2018.

Approximately $2.2 million of the $2.7 million revenue excess reflects the inclusion of savings from off-island purchases in determining the 2019 Test Year revenue requirement. Hydro is proposing to update the firm demand charge and the firm energy charge based on the 2019 Test Year Cost of Service Study, provided in Appendix D, to eliminate the forecast revenue excess for 2019 and reduce the customer rate impact of updating the RSP adjustments.

Approximately $0.5 million of the 2019 revenue excess reflects the reduction in specifically assigned costs as a result of changing from the existing specifically assigned O&M cost allocation methodology to the proposed 2017 GRA methodology which was accepted in the Supplemental Settlement Agreement. Therefore, Hydro believes it is reasonable to reflect this change in the proposed 2019 interim rates.

The overall projected average customer rate impact reflecting the combined effect of the January 1, 2019 RSP update and the concurrent implementation of the proposed interim base rates is an increase of 4.8%, a decrease of 6.4% relative to the impact of the Island Industrial RSP update impact of 11.2%. Appendix F provides the projected customer impacts reflecting the updated RSP adjustments and proposed interim base rates.

## 6.0 2019 Customer Rate Projections

### 6.1 Projected Rate Increases

As a result of the ongoing delay in the 2017 GRA process, Hydro has assumed that final GRA customer rates will be implemented July 1, 2019.

Table 7 provides the projected impacts for each customer class to become effective July 1, 2019. The projected impacts include the required revisions to base rates to recover 2019 Test Year costs, recovery/refund of the 2018 revenue deficiency/revenue excess and 2019 Test Year revenue deficiency/revenue excess over the agreed amortization periods, and the recovery of the deferred supply costs over the agreed amortization period.

**Table 7: Projected July 1, 2019 Increases in Customer Billings (Excluding RSP Impacts)**

| Customer Class | Customer Rate Impacts | | Average Unit Cost |
|---|---|---|---|
| | $ millions | % | cents/kWh |
| Newfoundland Power[30] | 28.8 | 6.3% | 8.369 |
| Island Industrial | 1.9 | 4.6% | 5.527 |
| Rural Labrador Interconnected | (0.6) | -2.6% | 2.836 |
| Labrador Industrial Transmission | 1.0 | 20.2% | $1.94/kW |
| Hydro Rural Government Diesel | 0.4 | 21.4% | 105.140 |
| Hydro Rural Other[31] | 2.5 | 4.0% | 13.367 |

Appendix G to this evidence provides the supporting calculations for the estimates of customer rate impacts reflecting 2017 GRA final rates. The projected increase in rates to Newfoundland Power's retail customers is 4.0% on July 1, 2019 as a result of the 2017 GRA.

Appendix H provides an update to Part B, Hydro Proposals filed with its 2017 GRA reflecting this updated evidence on customer rates.

## 7.0 Conclusion

This evidence provides estimated revenue requirements and projected rates reflecting the following: the three settlement agreements concluded during the 2017 GRA process; the

[30] Hydro notes that customer rates are also required to be updated each July 1st as a result of the operation of the RSP. The July 2019 customer rate impact of the RSP will not be known until Hydro's filing in May 2019.
[31] Includes Hydro Rural Isolated and Hydro Rural Interconnected, but excludes Hydro Rural Government Diesel. Hydro assumed Hydro Rural Other customers will receive the same rate increase as Newfoundland Power's retail customers, which is approximately 64% of Newfoundland Power's wholesale rate increase.

updated projection of savings from off-island purchases reflecting the proposed deferral of ~~O&M~~ costs for LIL and LTA; the updated fuel cost projection for 2019; and a July 1, 2019 GRA final rate implementation date.

Hydro has also proposed to implement revised interim rates for Island Industrial Customers to become effective January 1, 2019 to reduce the customer rate impacts resulting from the required update to the RSP adjustments in January 2019.

The revised rate projections provide for materially lower rates in 2019 for customers on the Island Interconnected System than the customer rates which were originally proposed in Hydro's 2017 GRA Application. The lower forecast customer rates primarily reflect the provision of savings from off-island purchases in the determination of rates for 2019 as required under the Expected Supply Scenario and savings in depreciation as a result of the 2017 GRA Settlement Agreement dated April 11, 2018.

# Appendix A

2018 Test Year Fuel Cost and Savings

Appendix A
Page 1 of 2

**Table 1: Derivation of Forecast 2018 Test Year No. 6 Fuel Expense**

| Month | 2015 Test Year No. 6 Fuel[1] (BBLS) | Adjustment for 2018 Test Year Load (BBLS) | 2018 Projected Savings from Off-Island Purchases[2] (BBLS) | Net 2018 Test Year No. 6 Fuel (BBLS) | 2015 Test Year Average Monthly Cost[3] ($/BBL) | Net 2018 Forecast No. 6 Fuel Expense ($000s) |
|---|---|---|---|---|---|---|
| | (a) | (b) | (c) | (d) = (a) + (b) + (c) | (e) | (f) = [(d) x (e)] /1000 |
| January | 415,518 | (3,361) | (507) | 411,650 | $57.55 | 23,690 |
| February | 375,307 | 47,363 | (32,379) | 390,291 | $59.85 | 23,359 |
| March | 395,728 | (123,970) | (3,311) | 268,447 | $61.41 | 16,485 |
| April | 255,307 | (16,410) | (2,813) | 236,084 | $61.41 | 14,498 |
| May | 197,864 | 2,677 | (15,541) | 185,000 | $62.64 | 11,588 |
| June | 76,586 | 134,079 | (6,393) | 204,272 | $62.64 | 12,796 |
| July | - | 6,869 | (6,869) | - | $62.64 | - |
| August | - | - | - | - | $62.64 | - |
| September | 25,534 | (25,534) | - | - | $62.64 | - |
| October | 164,887 | (102,740) | (22,389) | 39,757 | $66.51 | 2,644 |
| November | 255,307 | 10,000 | (32,298) | 233,010 | $71.70 | 16,707 |
| December | 415,618 | 48,693 | (123,535) | 340,777 | $76.05 | 25,916 |
| **Total** | **2,577,657** | **(22,333)** | **(246,036)** | **2,309,288** | | **147,684** |

[1] Hydro's Amended GRA Compliance Application P.U. 49(2016), Exhibit 2 - Computation of Revenue Requirements, Table 13.

[2]

| | |
|---|---|
| Off-Island Power Purchases (kWh) | 152,050,000 |
| 2015 Test Year Conversion Rate (BBLs/kWh) | 618 |
| Reduced Barrels (BBLs) | 246,036 |

[3] Hydro's Amended GRA Compliance Application P.U. 49(2016), Exhibit 2 - Computation of Revenue Requirements, Table 17.

**Table 2: Derivation of Forecast 2018 Test Year No. 6 Fuel Savings**

| Month | 2015 Test Year No. 6 Fuel Expense ($000s) | Net 2018 Forecast No. 6 Fuel Expense ($000s) | 2018 Projected Savings from Off-Island Purchases ($000s) |
|---|---|---|---|
| | (a) | (b) | (c) = (a) - (b) |
| January | 23,913 | 23,690 | 223 |
| February | 22,462 | 23,359 | (897) |
| March | 24,302 | 16,485 | 7,816 |
| April | 15,678 | 14,498 | 1,181 |
| May | 12,394 | 11,588 | 806 |
| June | 4,797 | 12,796 | (7,998) |
| July | - | - | - |
| August | - | - | - |
| September | 1,599 | - | 1,599 |
| October | 10,967 | 2,644 | 8,322 |
| November | 18,306 | 16,707 | 1,599 |
| December | 31,608 | 25,916 | 5,692 |
| **Total** | **166,026** | **147,684** | **18,342** |

# Appendix B

2019 Test Year Fuel Cost and Savings

**Table 1: Derivation of Forecast 2019 Test Year No. 6 Fuel Expense**

| **Month** | **2019 No. 6 Fuel Excluding Off-Island (BBLS)** | **2019 Projected Savings from Off-Island Purchases[1] (BBLS)** | **Net 2019 Test Year No. 6 Fuel (BBLS)** | **2019 Test Year Average Monthly Cost ($/BBL)** | **Net 2019 Forecast No. 6 Fuel Expense ($000s)** |
|---|---|---|---|---|---|
| | **(a)** | **(b)** | **(c) = (a) + (b)** | **(d)** | **(e) = [(c) x (d)] /1000** |
| January | 480,208 | (97,361) | 382,847 | $92.50 | 35,413 |
| February | 379,420 | (87,190) | 292,230 | $92.50 | 27,031 |
| March | 294,482 | (97,158) | 197,324 | $92.50 | 18,252 |
| April | 181,390 | (94,941) | 86,449 | $92.50 | 7,997 |
| May | 148,068 | (98,119) | 49,949 | $92.50 | 4,620 |
| June | 93,773 | (93,773) | - | $92.50 | - |
| July | 97,620 | (97,620) | - | $92.50 | - |
| August | 98,220 | (98,220) | - | $92.50 | - |
| September | 94,292 | (94,292) | - | $92.50 | - |
| October | 220,833 | (117,094) | 103,739 | $92.50 | 9,596 |
| November | 293,180 | (120,281) | 172,899 | $92.50 | 15,993 |
| December | 336,875 | (131,825) | 205,050 | $92.50 | 18,967 |
| **Total** | **2,718,361** | **(1,227,874)** | **1,490,487** | | **137,870** |

| | |
|---|---|
| [1] Off-Island Power Purchases (kWh) | 715,850,320 |
| 2019 Test Year Conversion Rate (BBLs/kWh) | 583 |
| Reduced Barrels (BBLs) | 1,227,874 |
| Cost ($/BBL) | 92.5 |
| **Total Projected 2019 Fuel Savings** | **113,578,310** |

# Appendix C

2018 Test Year Cost of Service Study Summary

**NEWFOUNDLAND AND LABRADOR HYDRO**
**2018 Expected Supply Test Year Cost of Service Study - October 26, 2018 Forecast**
**Total System Revenue Requirement**

| | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 |
|---|---|---|---|---|---|---|---|---|
| Line No. | Description | Total Amount | Island Interconnected | Island Isolated | Labrador Isolated | L'Anse au Loup | Labrador Interconnected | Basis of Proration |
| | Revenue Requirement | ($) | ($) | ($) | ($) | ($) | ($) | |
| | **Expenses** | | | | | | | |
| 1 | Operating, Maintenance and Admin. | 138,337,352 | 104,030,836 | 6,789,893 | 15,053,727 | 1,490,311 | 10,972,586 | Detailed Analysis |
| 2 | Fuels - No. 6 Fuel | 148,037,516 | 148,037,516 | - | - | - | - | Detailed Analysis |
| 3 | Fuels - Diesel | 17,266,585 | 87,144 | 2,140,854 | 14,364,592 | 634,623 | 39,373 | Detailed Analysis |
| 4 | Fuels - Gas Turbine | 3,711,024 | 3,473,692 | - | - | - | 237,332 | |
| 5 | Fuel Supply Deferral | - | - | | | | | |
| 6 | Power Purchases -CF(L)Co | 1,395,205 | - | - | - | - | 1,395,205 | Detailed Analysis |
| 7 | Power Purchases - Other | 62,310,678 | 59,241,500 | 176,972 | - | 2,837,205 | 55,000 | Detailed Analysis |
| 8 | Power Purchases - MF | - | - | | | | | |
| 8 | Power Purchases - LIL & LTA Costs | - | - | | | | | |
| 9 | Power Purchases - Off Island | 7,706,759 | 7,706,759 | | | | | |
| 10 | Depreciation | 74,963,444 | 66,031,104 | 723,490 | 3,149,254 | 784,964 | 4,274,632 | Detailed Analysis |
| | **Expense Credits:** | | | | | | | |
| 11 | Sundry | (456,000) | (342,916) | (22,381) | (49,621) | (4,912) | (36,169) | Total O&M Expenses |
| 12 | Building Rental Income | (15,600) | (15,600) | - | - | - | 0 | Detailed Analysis |
| 13 | Tax Refunds | - | - | - | - | - | - | Total O&M Expenses |
| 14 | Suppliers' Discounts | (39,600) | (29,780) | (1,944) | (4,309) | (427) | (3,141) | Total O&M Expenses |
| 15 | Pole Attachments | (1,578,275) | (1,137,383) | (23,451) | (102,027) | (67,660) | (247,754) | Detailed Analysis |
| 16 | Wheeling Revenues | - | 0 | - | - | - | - | Island Interconnected |
| 17 | Application Fees | (24,680) | (12,200) | (300) | (1,654) | (406) | (10,120) | Detailed Analysis |
| 18 | Meter Test Revenues | - | 0 | - | - | - | - | Weighted Customers |
| 19 | **Total Expense Credits** | **(2,114,155)** | **(1,537,878)** | **(48,076)** | **(157,612)** | **(73,405)** | **(297,184)** | |
| 20 | **Subtotal Expenses** | **451,614,408** | **387,070,672** | **9,783,133** | **32,409,961** | **5,673,697** | **16,676,944** | |
| 21 | Disposal Gain/Loss | - | - | - | - | - | - | Detailed Analysis |
| 22 | **Subtotal Rev Reqt Excl Return** | **451,614,408** | **387,070,672** | **9,783,133** | **32,409,961** | **5,673,697** | **16,676,944** | |
| 23 | Return on Debt | 91,798,240 | 82,588,881 | 659,387 | 3,335,030 | 686,653 | 4,528,289 | Rate Base |
| 24 | Return on Equity | 35,237,955 | 31,702,822 | 253,114 | 1,280,195 | 263,581 | 1,738,243 | Rate Base |
| 25 | **Total Revenue Requirement** | **578,650,604** | **501,362,376** | **10,695,634** | **37,025,186** | **6,623,932** | **22,943,476** | |

**NEWFOUNDLAND AND LABRADOR HYDRO**
**2018 Expected Supply Test Year Cost of Service Study - October 26, 2018 Forecast**
**Total System**
**Return on Rate Base**

| Line No | 1 | 2<br>Total<br>$ | 3<br>Island Interconnected<br>$ | 4<br>Island Isolated<br>$ | 5<br>Labrador Isolated<br>$ | 6<br>L'Anse au Loup<br>$ | 7<br>Labrador Interconnected<br>$ | 8<br>Basis of Proration |
|---|---|---|---|---|---|---|---|---|
| | **Rate Base:** | | | | | | | |
| 1 | Average Net Book Value | 2,054,005,042 | 1,844,981,477 | 14,918,521 | 74,540,490 | 15,707,477 | 103,857,077 | Schedule 2.3 |
| 2 | Cash Working Capital | 2,162,000 | 1,941,986 | 15,703 | 78,460 | 16,533 | 109,318 | Prorated on Average Net Book Value - L. 1 |
| 3 | Fuel Inventory - No. 6 Fuel | 57,754,996 | 57,754,996 | - | - | - | - | Specifically Assigned - Holyrood |
| 4 | Fuel Inventory - Diesel | 2,994,759 | 102,326 | 357,296 | 2,379,253 | 93,027 | 62,856 | Detailed Fuel Analysis |
| 5 | Fuel Inventory - Gas Turbine | 4,877,967 | 4,652,200 | - | - | - | 225,767 | Detailed Fuel Analysis |
| 6 | Inventory/Supplies | 33,034,000 | 29,348,869 | 179,428 | 1,290,289 | 286,152 | 1,929,263 | Prorated on Total Plant in Service, Schedule 2.2 |
| 7 | Deferred Charges: Holyrood | - | - | | | | | Detailed Analysis |
| 8 | Deferred Charges: Foreign Exchange Loss and Regulatory Costs | 82,041,000 | 73,692,188 | 595,875 | 2,977,294 | 627,388 | 4,148,256 | Prorated on Average Net Book Value - L. 1 |
| 9 | Retired Asset Pool | 7,585,989 | 6,814,009 | 55,098 | 275,298 | 58,012 | 383,572 | Prorated on Average Net Book Value - L. 1 |
| 10 | Total Rate Base | **2,244,455,753** | **2,019,288,052** | **16,121,920** | **81,541,083** | **16,788,589** | **110,716,108** | |
| 11 | Less: Rural Portion | - | - | - | - | - | - | Schedule 2.6, L. 9 |
| 12 | Rate Base Available for Equity Return | **2,244,455,753** | **2,019,288,052** | **16,121,920** | **81,541,083** | **16,788,589** | **110,716,108** | |
| | **Corporate Targets:** | | | | | | | |
| 13 | Capital Structure: Percent of Debt | 77.83% (1) | | | | | | |
| 14 | Return | 5.25% | | | | | | |
| 15 | Weighted Average Return: Debt | **4.09%** | | | | | | |
| 16 | Capital Structure: Percent of Equity | 18.48% (1) | | | | | | |
| 17 | Return | 8.50% | | | | | | |
| 18 | Weighted Average Return: Equity | **1.57%** | | | | | | |
| 19 | Weighted Average Cost of Capital | **5.66%** | | | | | | |
| | **Return on Rate Base by System (%):** | | | | | | | |
| 20 | Return on Rate Base - Debt Component | - | 4.09% | 4.09% | 4.09% | 4.09% | 4.09% | |
| 21 | Return on Rate Base - Equity Component | - | 1.57% | 1.57% | 1.57% | 1.57% | 1.57% | |
| | **Return on Rate Base ($):** | | | | | | | |
| 22 | Return on Debt | 91,798,240 | 82,588,881 | 659,387 | 3,335,030 | 686,653 | 4,528,289 | Schedule 2.6, L.13 |
| 23 | Return on Equity | 35,237,955 | 31,702,822 | 253,114 | 1,280,195 | 263,581 | 1,738,243 | Schedule 2.6, L.14 |
| 24 | Return on Rate Base ($) | **127,036,196** | **114,291,704** | **912,501** | **4,615,225** | **950,234** | **6,266,532** | Schedule 2.6, L.15 |
| | **Return on Total Rate Base (%):** | | | | | | | |
| 25 | Return on Rate Base - Debt Component | 4.09% | 4.09% | 4.09% | 4.09% | 4.09% | 4.09% | L. 22 divided by L.10 |
| 26 | Return on Rate Base - Equity Component | 1.57% | 1.57% | 1.57% | 1.57% | 1.57% | 1.57% | L. 23 divided by L.10 |
| 27 | Return on Rate Base (%) | **5.66%** | **5.66%** | **5.66%** | **5.66%** | **5.66%** | **5.66%** | L. 24 divided by L.10 |

(1) Debt and equity weightings reflect a 0.62% funded ARO and 3.08% component for Employee Future Benefits at 0% cost.

**NEWFOUNDLAND AND LABRADOR HYDRO**
**2018 Expected Supply Test Year Cost of Service Study - October 26, 2018 Forecast**
**Total System**
**Comparison of Revenue & Allocated Revenue Requirement**

| | 1 | 2 | 3 | 4 | 5 | 6 | 7 |
|---|---|---|---|---|---|---|---|
| Line No. | Rate Class | Revenues ($) | Cost of Service Before Deficit and Revenue Credit Allocation ($) | Revenue Credits ($) | Deficit ($) | Revenue Requirement After Deficit and Revenue Credit Allocation (Col.3+4+5) ($) | Revenue to Cost Coverage (Col.2/3) |
| | **Total System** | | | | | | |
| 1 | Newfoundland Power | 441,522,342 | 392,787,557 | - | 58,064,862 | 450,852,419 | |
| 2 | Subtotal Newfoundland Power | **441,522,342** | **392,787,557** | **-** | **58,064,862** | **450,852,419** | **1.12** |
| 3 | Island Industrial | 41,174,619 | 39,071,760 | - | - | 39,071,760 | 1.05 |
| 4 | Labrador Industrial | 4,739,196 | 4,857,979 | - | - | 4,857,979 | 0.98 |
| 5 | CFB - Goose Bay Secondary | - | - | - | - | - | - |
| 6 | Rural Labrador Interconnected | 20,984,405 | 18,085,497 | - | 2,673,537 | 20,759,034 | 1.16 |
| | **Rural Deficit Areas** | | | | | | |
| 7 | Island Interconnected | 49,927,947 | 69,503,058 | - | (19,575,112) | 49,927,947 | 0.72 |
| 8 | Island Isolated | 1,550,692 | 10,695,317 | - | (9,144,625) | 1,550,692 | 0.14 |
| 9 | Labrador Isolated | 8,663,855 | 37,025,186 | - | (28,361,331) | 8,663,855 | 0.23 |
| 10 | L'Anse au Loup | 2,966,601 | 6,623,932 | - | (3,657,331) | 2,966,601 | 0.45 |
| 11 | CFB Revenue Credit Applied to Deficit | - | - | - | - | - | - |
| 12 | **Subtotal** | **63,109,094** | **123,847,493** | **-** | **(60,738,398)** | **63,109,094** | **0.51** |
| 13 | **Total** | **571,529,656** | **578,650,286** | **-** | **-** | **578,650,286** | **0.99** |

**NEWFOUNDLAND AND LABRADOR HYDRO**
**2018 Expected Supply Test Year Cost of Service Study - October 26, 2018 Forecast**
**Island Interconnected**
**Comparison of Revenue & Allocated Revenue Requirement**

| Line No. | 1<br>Rate Class | 2<br>Revenues<br>($) | 3<br>Cost of Service Before Deficit and Revenue Credit Allocation<br>($) | 4<br>Revenue Credit<br>($) | 5<br>Deficit Allocation<br>($) | 6<br>Revenue Requirement After Deficit and Revenue Credit Allocation (Col.3+4+5)<br>($) | 7<br>Revenue to Cost Coverage (Col.2/3) |
|---|---|---|---|---|---|---|---|
| | **Island Interconnected** | | | | | | |
| 1 | Newfoundland Power | 441,522,342 | 392,787,557 | - | 58,064,862 | 450,852,419 | |
| 2 | **Subtotal Newfoundland Power** | **441,522,342** | **392,787,557** | **-** | **58,064,862** | **450,852,419** | **1.12** |
| 3 | Industrial - Firm | 41,174,619 | 39,071,760 | - | | 39,071,760 | |
| 4 | Industrial - Non-Firm | - | - | - | | - | |
| 5 | **Subtotal Industrial** | **41,174,619** | **39,071,760** | **-** | **-** | **39,071,760** | **1.05** |
| | **Rural** | | | | | | |
| 6 | 1.1 Domestic | 13,522,976 | 21,926,361 | - | (8,403,385) | 13,522,976 | 0.62 |
| 7 | 1.12 Domestic All Electric | 17,034,575 | 24,766,176 | - | (7,731,601) | 17,034,575 | 0.69 |
| 8 | 1.3 Special | 19,223 | 68,113 | - | (48,890) | 19,223 | 0.28 |
| 9 | 2.1 General Service 0-100 kW | 9,123,833 | 11,483,377 | - | (2,359,545) | 9,123,833 | 0.79 |
| 10 | 2.3 General Service 110-1,000 kVa | 5,944,059 | 6,581,479 | - | (637,419) | 5,944,059 | 0.90 |
| 11 | 2.4 General Service Over 1,000 kVa | 3,289,595 | 3,460,580 | - | (170,985) | 3,289,595 | 0.95 |
| 12 | 4.1 Street and Area Lighting | 993,685 | 1,216,973 | - | (223,288) | 993,685 | 0.82 |
| 13 | **Subtotal Rural** | **49,927,947** | **69,503,058** | **-** | **(19,575,112)** | **49,927,947** | **0.72** |
| 14 | **Total Island Interconnected** | **532,624,908** | **501,362,376** | **-** | **38,489,750** | **539,852,127** | **1.06** |

**NEWFOUNDLAND AND LABRADOR HYDRO**
**2018 Expected Supply Test Year Cost of Service Study - October 26, 2018 Forecast**
**Island Isolated**
**Comparison of Revenue & Allocated Revenue Requirement**

| | 1 | 2 | 3 | 4 | 5 | 6 | 7 |
|---|---|---|---|---|---|---|---|
| Line No. | Rate Class | Revenues ($) | Cost of Service Before Deficit and Revenue Credit Allocation ($) | Revenue Credit ($) | Deficit ($) | Revenue Requirement After Deficit and Revenue Credit Allocation (Col.3+4+5) ($) | Revenue to Cost Coverage (Col.2/3) |
| | **Island Isolated** | | | | | | |
| 1 | 1.2 Domestic Diesel | 779,446 | 8,232,523 | | (7,453,077) | 779,446 | 0.09 |
| 2 | 1.2G Government Domestic Diesel | - | - | | - | - | - |
| 2 | 1.23 Churches, Schools & Com Halls | 63,100 | 317,210 | | (254,110) | 63,100 | 0.20 |
| 3 | 2.1 General Service 0-10 kW | 205,207 | 846,144 | | (640,938) | 205,207 | 0.24 |
| 4 | 2.2 GS 10-100 kW | 459,017 | 1,095,748 | | (636,732) | 459,017 | 0.42 |
| 5 | 4.1 Street and Area Lighting | 38,040 | 194,316 | | (156,276) | 38,040 | 0.20 |
| 6 | 4.1G Gov't Street and Area Lighting | 5,882 | 9,375 | | (3,493) | 5,882 | 0.63 |
| 7 | **Total** | **1,550,692** | **10,695,317** | | **(9,144,625)** | **1,550,692** | **0.14** |

**NEWFOUNDLAND AND LABRADOR HYDRO**
**2018 Expected Supply Test Year Cost of Service Study - October 26, 2018 Forecast**
**Labrador Isolated**
**Comparison of Revenue & Allocated Revenue Requirement**

| | 1 | 2 | 3 | 4 | 5 | 6 | 7 |
|---|---|---|---|---|---|---|---|
| Line No. | Rate Class | Revenues ($) | Cost of Service Before Deficit and Revenue Credit Allocation ($) | Revenue Credit ($) | Deficit ($) | Revenue Requirement After Deficit and Revenue Credit Allocation (Col.3+4+5) ($) | Revenue to Cost Coverage (Col.2/3) |
| | **Labrador Isolated** | | | | | | |
| 1 | 1.2 Domestic Diesel | 3,032,845 | 19,925,606 | | (16,892,761) | 3,032,845 | 0.15 |
| 2 | 1.2G Government Domestic Diesel | 517,117 | 535,622 | | (18,505) | 517,117 | 0.97 |
| 3 | 1.23 Churches, Schools & Com Halls | 277,232 | 1,082,918 | | (805,687) | 277,232 | 0.26 |
| 4 | 2.1 General Service 0-10 kW | 1,241,157 | 3,643,401 | | (2,402,244) | 1,241,157 | 0.34 |
| 5 | 2.2 GS 10-100 kW | 3,008,584 | 8,558,850 | | (5,550,265) | 3,008,584 | 0.35 |
| 6 | 2.3 GS 110-1,000 kVa | 243,729 | 1,352,604 | | (1,108,875) | 243,729 | 0.18 |
| 7 | 2.4 General Service Over 1,000 kVa | 224,074 | 1,560,085 | | (1,336,011) | 224,074 | 0.14 |
| 8 | 4.1 Street and Area Lighting | 110,871 | 356,374 | | (245,503) | 110,871 | 0.31 |
| 9 | 4.1G Gov't Street and Area Lighting | 8,246 | 9,726 | | (1,480) | 8,246 | 0.85 |
| 10 | **Total** | **8,663,855** | **37,025,186** | | **(28,361,331)** | **8,663,855** | **0.23** |

**NEWFOUNDLAND AND LABRADOR HYDRO**
**2018 Expected Supply Test Year Cost of Service Study - October 26, 2018 Forecast**
**L'Anse au Loup**
**Comparison of Revenue & Allocated Revenue Requirement**

| Line No. | 1<br>Rate Class | 2<br>Revenues<br>($) | 3<br>Cost of Service Before Deficit and Revenue Credit Allocation<br>($) | 4<br>Revenue Credit<br>($) | 5<br>Deficit<br>($) | 6<br>Revenue Requirement After Deficit and Revenue Credit Allocation (Col.3+4+5)<br>($) | 7<br>Revenue to Cost Coverage (Col.2/3) |
|---|---|---|---|---|---|---|---|
| | **L'Anse au Loup** | | | | | | |
| 1 | 1.1 Domestic | 550,885 | 1,403,020 | | (852,135) | 550,885 | 0.39 |
| 2 | 1.12 Domestic All Electric | 1,296,197 | 3,062,018 | | (1,765,821) | 1,296,197 | 0.42 |
| 3 | 2.1 General Service 0-100 kW | 789,492 | 1,579,608 | | (790,116) | 789,492 | 0.50 |
| 3 | 2.3 General Service 110-1,000 kVa | 311,102 | 535,974 | | (224,872) | 311,102 | 0.58 |
| 4 | 4.1 Street and Area Lighting | 18,925 | 43,311 | | (24,387) | 18,925 | 0.44 |
| 5 | **Total L'Anse Au Loup** | **2,966,601** | **6,623,932** | | **(3,657,331)** | **2,966,601** | **0.45** |

**NEWFOUNDLAND AND LABRADOR HYDRO**
**2018 Expected Supply Test Year Cost of Service Study - October 26, 2018 Forecast**
**Labrador Interconnected**
**Comparison of Revenue & Allocated Revenue Requirement**

| | 1 | 2 | 3 | 4 | 5 | 6 | 7 |
|---|---|---|---|---|---|---|---|
| Line No. | Rate Class | Revenues | Cost of Service Before Deficit and Revenue Credit Allocation | Revenue Credit | Deficit Allocation | Revenue Requirement After Deficit and Revenue Credit Allocation (Col.3+4+5) | Revenue to Cost Coverage (Col.2/7) |
| | | ($) | ($) | ($) | ($) | ($) | |
| | **Labrador Interconnected** | | | | | | |
| 1 | Labrador Industrial Firm | 4,739,196 | 4,857,979 | | - | 4,857,979 | 0.98 |
| 2 | Labrador Industrial Non-Firm | - | - | | - | - | - |
| 3 | **Subtotal Industrial** | **4,739,196** | **4,857,979** | **-** | **-** | **4,857,979** | |
| 4 | CFB - Goose Bay Secondary | - | - | - | - | - | - |
| | **Rural** | | | | | | |
| 5 | 1.1 Domestic | 101,567 | 204,383 | - | 30,213.47 | 234,597 | 0.43 |
| 6 | 1.1A Domestic All Electric | 10,901,824 | 10,623,681 | - | 1,570,474 | 12,194,155 | 0.89 |
| 7 | 2.1 General Service 0-10 kW | 370,747 | 351,378 | - | 51,943 | 403,321 | 0.92 |
| 8 | 2.2 General Service 10-100 kW | 2,295,257 | 1,664,633 | - | 246,079 | 1,910,712 | 1.20 |
| 9 | 2.3 General Service 110-1,000 kVa | 3,685,870 | 2,350,760 | - | 347,507 | 2,698,267 | 1.37 |
| 10 | 2.4 General Service Over 1,000 kVa | 3,267,874 | 2,597,868 | - | 384,037 | 2,981,905 | 1.10 |
| 11 | 4.1 Street and Area Lighting | 361,265 | 292,794 | - | 43,283 | 336,077 | 1.07 |
| 12 | **Subtotal Rural** | **20,984,405** | **18,085,497** | **-** | **2,673,537** | **20,759,034** | |
| 13 | **Total Labrador Interconnected** | **25,723,601** | **22,943,476** | **-** | **2,673,537** | **25,617,012** | |

**NEWFOUNDLAND AND LABRADOR HYDRO**
**2018 Expected Supply Test Year Cost of Service Study - October 26, 2018 Forecast**
**Total System**
**Rural Deficit Allocation**

| Line No. | 1 | 2 | | |
|---|---|---|---|---|
| | | Deficit Allocation<br>Allocated on<br>Revenue Requirment<br>($) | | |
| | ALLOCATION OF DEFICIT: | | | |
| 1 | Island Interconnected | 58,064,862 | | |
| 2 | Labrador Interconnected | 2,673,537 | | |
| 3 | **Allocated Totals** | **60,738,398** | | |
| | CUSTOMER DEFICIT ALLOCATION: | | | |
| | | Amount | Revenue Requirement | Percent |
| | **Island Interconnected:** | | | |
| 4 | Newfoundland Power | 58,064,862 | 392,787,557 | 95.6% |
| | **Labrador Interconnected:** | | | |
| 5 | Rural Labrador Interconnected | 2,673,537 | 18,085,497 | 4.4% |
| 6 | **Total** | **60,738,398** | | 100.0% |

# Appendix D

2019 Test Year Cost of Service Study Summary

**NEWFOUNDLAND AND LABRADOR HYDRO**
**2019 Expected Supply Test Year Cost of Service Study - October 26, 2018 Update**
**Total System Revenue Requirement**

| Line No. | 1<br>Description | 2<br>Total Amount ($) | 3<br>Island Interconnected ($) | 4<br>Island Isolated ($) | 5<br>Labrador Isolated ($) | 6<br>L'Anse au Loup ($) | 7<br>Labrador Interconnected ($) | 8<br>Basis of Proration |
|---|---|---|---|---|---|---|---|---|
| | Revenue Requirement | | | | | | | |
| | **Expenses** | | | | | | | |
| 1 | Operating, Maintenance and Admin. | 140,793,862 | 105,785,497 | 6,974,717 | 15,423,291 | 1,504,886 | 11,105,471 | Detailed Analysis |
| 2 | Fuels - No. 6 Fuel | 138,205,264 | 138,205,264 | - | - | - | - | Detailed Analysis |
| 3 | Fuels - Diesel | 21,146,184 | 138,012 | 2,420,900 | 17,777,900 | 767,000 | 42,372 | Detailed Analysis |
| 4 | Fuels - Gas Turbine | 7,415,356 | 7,160,521 | - | - | - | 254,835 | |
| 5 | Fuel Supply Deferral | - | - | | | | | |
| 6 | Power Purchases -CF(L)Co | 1,490,325 | - | - | - | - | 1,490,325 | Detailed Analysis |
| 7 | Power Purchases - Other | 66,399,859 | 62,307,563 | 195,500 | - | 3,731,796 | 165,000 | Detailed Analysis |
| 8 | Power Purchases - MF | - | - | | | | | |
| 8 | Power Purchases - LIL & LTA Costs | - | - | | | | | |
| 9 | Power Purchases - Off Island | 6,373,177 | 6,373,177 | | | | | |
| 10 | Depreciation | 80,922,570 | 70,939,035 | 840,772 | 3,868,483 | 789,941 | 4,484,338 | Detailed Analysis |
| | **Expense Credits:** | | | | | | | |
| 11 | Sundry | (456,000) | (342,616) | (22,590) | (49,953) | (4,874) | (35,968) | Total O&M Expenses |
| 12 | Building Rental Income | (15,600) | (15,600) | - | - | - | 0 | Detailed Analysis |
| 13 | Tax Refunds | - | - | - | - | - | - | Total O&M Expenses |
| 14 | Suppliers' Discounts | (39,600) | (29,753) | (1,962) | (4,338) | (423) | (3,124) | Total O&M Expenses |
| 15 | Pole Attachments | (1,598,389) | (1,151,878) | (23,750) | (103,327) | (68,522) | (250,912) | Detailed Analysis |
| 16 | Wheeling Revenues | - | 0 | - | - | - | - | Island Interconnected |
| 17 | Application Fees | (24,680) | (12,200) | (300) | (1,654) | (406) | (10,120) | Detailed Analysis |
| 18 | Meter Test Revenues | - | 0 | - | - | - | - | Weighted Customers |
| 19 | **Total Expense Credits** | **(2,134,269)** | **(1,552,047)** | **(48,601)** | **(159,272)** | **(74,225)** | **(300,124)** | |
| 20 | **Subtotal Expenses** | **460,612,327** | **389,357,022** | **10,383,288** | **36,910,402** | **6,719,398** | **17,242,218** | |
| 21 | Disposal Gain/Loss | - | - | - | - | - | - | Detailed Analysis |
| 22 | **Subtotal Rev Reqt Excl Return** | **460,612,327** | **389,357,022** | **10,383,288** | **36,910,402** | **6,719,398** | **17,242,218** | |
| 23 | Return on Debt | 92,942,206 | 82,695,750 | 753,948 | 3,852,364 | 653,423 | 4,986,721 | Rate Base |
| 24 | Return on Equity | 38,297,793 | 34,075,636 | 310,672 | 1,587,406 | 269,250 | 2,054,830 | Rate Base |
| 25 | **Total Revenue Requirement** | **591,852,326** | **506,128,408** | **11,447,907** | **42,350,172** | **7,642,071** | **24,283,768** | |

**NEWFOUNDLAND AND LABRADOR HYDRO**
**2019 Expected Supply Test Year Cost of Service Study - October 26, 2018 Update**
**Total System**
**Return on Rate Base**

| Line No | 1 | 2<br>Total<br>$ | 3<br>Island Interconnected<br>$ | 4<br>Island Isolated<br>$ | 5<br>Labrador Isolated<br>$ | 6<br>L'Anse au Loup<br>$ | 7<br>Labrador Interconnected<br>$ | 8<br>Basis of Proration |
|---|---|---|---|---|---|---|---|---|
| | **Rate Base:** | | | | | | | |
| 1 | Average Net Book Value | 2,162,232,839 | 1,921,725,720 | 17,649,807 | 89,303,558 | 15,414,005 | 118,139,749 | Schedule 2.3 |
| 2 | Cash Working Capital | 1,434,000 | 1,274,495 | 11,705 | 59,226 | 10,223 | 78,351 | Prorated on Average Net Book Value - L. 1 |
| 3 | Fuel Inventory - No. 6 Fuel | 42,899,392 | 42,899,392 | - | - | - | - | Specifically Assigned - Holyrood |
| 4 | Fuel Inventory - Diesel | 3,044,251 | 102,326 | 363,540 | 2,420,572 | 94,956 | 62,856 | Detailed Fuel Analysis |
| 5 | Fuel Inventory - Gas Turbine | 5,068,087 | 4,843,004 | - | - | - | 225,084 | Detailed Fuel Analysis |
| 6 | Inventory/Supplies | 32,884,000 | 29,020,470 | 202,738 | 1,388,849 | 273,518 | 1,998,426 | Prorated on Total Plant in Service, Schedule 2.2 |
| 7 | Deferred Charges: Holyrood | - | - | | | | | Detailed Analysis |
| 8 | Deferred Charges: Foreign Exchange Loss and Regulatory Costs | 75,958,000 | 67,509,123 | 620,028 | 3,137,183 | 541,485 | 4,150,182 | Prorated on Average Net Book Value - L. 1 |
| 9 | Retired Asset Pool | 11,710,730 | 10,408,135 | 95,592 | 483,671 | 83,483 | 639,849 | Prorated on Average Net Book Value - L. 1 |
| 10 | Total Rate Base | **2,335,231,298** | **2,077,782,665** | **18,943,410** | **96,793,059** | **16,417,670** | **125,294,495** | |
| 11 | Less: Rural Portion | - | - | - | - | - | - | Schedule 2.6, L. 9 |
| 12 | Rate Base Available for Equity Return | **2,335,231,298** | **2,077,782,665** | **18,943,410** | **96,793,059** | **16,417,670** | **125,294,495** | |
| | **Corporate Targets:** | | | | | | | |
| 13 | Capital Structure: Percent of Debt | 77.08% [(1)] | | | | | | |
| 14 | Return | 5.17% | | | | | | |
| 15 | Weighted Average Return: Debt | **3.98%** | | | | | | |
| 16 | Capital Structure: Percent of Equity | 19.25% [(1)] | | | | | | |
| 17 | Return | 8.50% | | | | | | |
| 18 | Weighted Average Return: Equity | **1.64%** | | | | | | |
| 19 | Weighted Average Cost of Capital | **5.62%** | | | | | | |
| | **Return on Rate Base by System (%):** | | | | | | | |
| 20 | Return on Rate Base - Debt Component | - | 3.98% | 3.98% | 3.98% | 3.98% | 3.98% | |
| 21 | Return on Rate Base - Equity Component | - | 1.64% | 1.64% | 1.64% | 1.64% | 1.64% | |
| | **Return on Rate Base ($):** | | | | | | | |
| 22 | Return on Debt | 92,942,206 | 82,695,750 | 753,948 | 3,852,364 | 653,423 | 4,986,721 | Schedule 2.6, L.12 |
| 23 | Return on Equity | 38,297,793 | 34,075,636 | 310,672 | 1,587,406 | 269,250 | 2,054,830 | Schedule 2.6, L.13 |
| 24 | Return on Rate Base ($) | **131,239,999** | **116,771,386** | **1,064,620** | **5,439,770** | **922,673** | **7,041,551** | Schedule 2.6, L.14 |
| | **Return on Total Rate Base (%):** | | | | | | | |
| 25 | Return on Rate Base - Debt Component | 3.98% | 3.98% | 3.98% | 3.98% | 3.98% | 3.98% | L. 22 divided by L.10 |
| 26 | Return on Rate Base - Equity Component | 1.64% | 1.64% | 1.64% | 1.64% | 1.64% | 1.64% | L. 23 divided by L.10 |
| 27 | Return on Rate Base (%) | **5.62%** | **5.62%** | **5.62%** | **5.62%** | **5.62%** | **5.62%** | L. 24 divided by L.10 |

(1) Debt and equity weightings reflect a 0.58% funded ARO and 3.09% component for Employee Future Benefits at 0% cost.

**NEWFOUNDLAND AND LABRADOR HYDRO**
**2019 Expected Supply Test Year Cost of Service Study - October 26, 2018 Update**
**Total System**
**Comparison of Revenue & Allocated Revenue Requirement**

| | 1 | 2 | 3 | 4 | 5 | 6 | 7 |
|---|---|---|---|---|---|---|---|
| Line No. | Rate Class | Revenues ($) | Cost of Service Before Deficit and Revenue Credit Allocation ($) | Revenue Credits ($) | Deficit ($) | Revenue Requirement After Deficit and Revenue Credit Allocation (Col.3+4+5) ($) | Revenue to Cost Coverage (Col.2/3) |
| | **Total System** | | | | | | |
| 1 | Newfoundland Power | 459,777,954 | 396,924,408 | - | 62,835,316 | 459,759,724 | |
| 2 | Subtotal Newfoundland Power | **459,777,954** | **396,924,408** | **-** | **62,835,316** | **459,759,724** | **1.16** |
| 3 | Island Industrial | 39,103,710 | 39,105,053 | - | - | 39,105,053 | 1.00 |
| 4 | Labrador Industrial | 5,579,486 | 5,582,412 | - | - | 5,582,412 | 1.00 |
| 5 | CFB - Goose Bay Secondary | - | - | - | - | - | - |
| 6 | Rural Labrador Interconnected | 21,669,705 | 18,701,356 | - | 2,960,527 | 21,661,883 | 1.16 |
| | **Rural Deficit Areas** | | | | | | |
| 7 | Island Interconnected | 51,673,173 | 70,098,946 | - | (18,425,774) | 51,673,173 | 0.74 |
| 8 | Island Isolated | 1,659,717 | 11,447,543 | - | (9,787,826) | 1,659,717 | 0.14 |
| 9 | Labrador Isolated | 9,277,722 | 42,350,172 | - | (33,072,450) | 9,277,722 | 0.22 |
| 10 | L'Anse au Loup | 3,132,278 | 7,642,071 | - | (4,509,793) | 3,132,278 | 0.41 |
| 11 | CFB Revenue Credit Applied to Deficit | - | - | - | - | - | - |
| 12 | **Subtotal** | **65,742,889** | **131,538,733** | **-** | **(65,795,844)** | **65,742,889** | **0.50** |
| 13 | **Total** | **591,873,744** | **591,851,962** | **-** | **-** | **591,851,962** | **1.00** |

**NEWFOUNDLAND AND LABRADOR HYDRO**
**2019 Expected Supply Test Year Cost of Service Study - October 26, 2018 Update**
**Island Interconnected**
**Comparison of Revenue & Allocated Revenue Requirement**

| Line No. | 1<br>Rate Class | 2<br>Revenues<br>($) | 3<br>Cost of Service Before Deficit and Revenue Credit Allocation<br>($) | 4<br>Revenue Credit<br>($) | 5<br>Deficit Allocation<br>($) | 6<br>Revenue Requirement After Deficit and Revenue Credit Allocation (Col.3+4+5)<br>($) | 7<br>Revenue to Cost Coverage (Col.2/3) |
|---|---|---|---|---|---|---|---|
| | **Island Interconnected** | | | | | | |
| 1 | Newfoundland Power | 459,777,954 | 396,924,408 | - | 62,835,316 | 459,759,724 | |
| 2 | **Subtotal Newfoundland Power** | **459,777,954** | **396,924,408** | **-** | **62,835,316** | **459,759,724** | **1.16** |
| 3 | Industrial - Firm | 39,103,710 | 39,105,053 | - | | 39,105,053 | |
| 4 | Industrial - Non-Firm | - | - | - | | - | |
| 5 | **Subtotal Industrial** | **39,103,710** | **39,105,053** | **-** | **-** | **39,105,053** | **1.00** |
| | **Rural** | | | | | | |
| 6 | 1.1 Domestic | 14,148,092 | 22,336,326 | - | (8,188,234) | 14,148,092 | 0.63 |
| 7 | 1.12 Domestic All Electric | 17,912,544 | 25,173,650 | - | (7,261,106) | 17,912,544 | 0.71 |
| 8 | 1.3 Special | 19,468 | 69,631 | - | (50,163) | 19,468 | 0.28 |
| 9 | 2.1 General Service 0-100 kW | 9,285,301 | 11,432,823 | - | (2,147,522) | 9,285,301 | 0.81 |
| 10 | 2.3 General Service 110-1,000 kVa | 5,994,009 | 6,476,028 | - | (482,020) | 5,994,009 | 0.93 |
| 11 | 2.4 General Service Over 1,000 kVa | 3,307,404 | 3,387,343 | - | (79,939) | 3,307,404 | 0.98 |
| 12 | 4.1 Street and Area Lighting | 1,006,355 | 1,223,145 | - | (216,790) | 1,006,355 | 0.82 |
| 13 | **Subtotal Rural** | **51,673,173** | **70,098,946** | **-** | **(18,425,774)** | **51,673,173** | **0.74** |
| 14 | **Total Island Interconnected** | **550,554,837** | **506,128,408** | **-** | **44,409,543** | **550,537,950** | **1.09** |

**NEWFOUNDLAND AND LABRADOR HYDRO**
**2019 Expected Supply Test Year Cost of Service Study - October 26, 2018 Update**
**Island Isolated**
**Comparison of Revenue & Allocated Revenue Requirement**

| | 1 | 2 | 3 | 4 | 5 | 6 | 7 |
|---|---|---|---|---|---|---|---|
| Line No. | Rate Class | Revenues ($) | Cost of Service Before Deficit and Revenue Credit Allocation ($) | Revenue Credit ($) | Deficit ($) | Revenue Requirement After Deficit and Revenue Credit Allocation (Col.3+4+5) ($) | Revenue to Cost Coverage (Col.2/3) |
| | **Island Isolated** | | | | | | |
| 1 | 1.2 Domestic Diesel | 814,032 | 8,801,149 | | (7,987,117) | 814,032 | 0.09 |
| 2 | 1.2G Government Domestic Diesel | - | - | | - | - | - |
| 2 | 1.23 Churches, Schools & Com Halls | 66,100 | 341,357 | | (275,257) | 66,100 | 0.19 |
| 3 | 2.1 General Service 0-10 kW | 224,256 | 912,528 | | (688,272) | 224,256 | 0.25 |
| 4 | 2.2 GS 10-100 kW | 510,480 | 1,172,197 | | (661,716) | 510,480 | 0.44 |
| 5 | 4.1 Street and Area Lighting | 38,525 | 210,466 | | (171,940) | 38,525 | 0.18 |
| 6 | 4.1G Gov't Street and Area Lighting | 6,323 | 9,847 | | (3,524) | 6,323 | 0.64 |
| 7 | **Total** | **1,659,717** | **11,447,543** | | **(9,787,826)** | **1,659,717** | **0.14** |

**NEWFOUNDLAND AND LABRADOR HYDRO**
**2019 Expected Supply Test Year Cost of Service Study - October 26, 2018 Update**
**Labrador Isolated**
**Comparison of Revenue & Allocated Revenue Requirement**

| | 1 | 2 | 3 | 4 | 5 | 6 | 7 |
|---|---|---|---|---|---|---|---|
| Line No. | Rate Class | Revenues ($) | Cost of Service Before Deficit and Revenue Credit Allocation ($) | Revenue Credit ($) | Deficit ($) | Revenue Requirement After Deficit and Revenue Credit Allocation (Col.3+4+5) ($) | Revenue to Cost Coverage (Col.2/3) |
| | **Labrador Isolated** | | | | | | |
| 1 | 1.2 Domestic Diesel | 3,198,936 | 22,740,468 | | (19,541,532) | 3,198,936 | 0.14 |
| 2 | 1.2G Government Domestic Diesel | 632,628 | 607,122 | | 25,506 | 632,628 | 1.04 |
| 3 | 1.23 Churches, Schools & Com Halls | 290,756 | 1,252,208 | | (961,453) | 290,756 | 0.23 |
| 4 | 2.1 General Service 0-10 kW | 1,349,414 | 4,189,177 | | (2,839,763) | 1,349,414 | 0.32 |
| 5 | 2.2 GS 10-100 kW | 3,203,130 | 9,784,539 | | (6,581,409) | 3,203,130 | 0.33 |
| 6 | 2.3 GS 110-1,000 kVa | 251,613 | 1,565,927 | | (1,314,314) | 251,613 | 0.16 |
| 7 | 2.4 General Service Over 1,000 kVa | 230,095 | 1,803,574 | | (1,573,479) | 230,095 | 0.13 |
| 8 | 4.1 Street and Area Lighting | 112,285 | 397,589 | | (285,304) | 112,285 | 0.28 |
| 9 | 4.1G Gov't Street and Area Lighting | 8,864 | 9,567 | | (703) | 8,864 | 0.93 |
| 10 | **Total** | **9,277,722** | **42,350,172** | | **(33,072,450)** | **9,277,722** | **0.22** |

**NEWFOUNDLAND AND LABRADOR HYDRO**
**2019 Expected Supply Test Year Cost of Service Study - October 26, 2018 Update**
**L'Anse au Loup**
**Comparison of Revenue & Allocated Revenue Requirement**

| | 1 | 2 | 3 | 4 | 5 | 6 | 7 |
|---|---|---|---|---|---|---|---|
| Line No. | Rate Class | Revenues ($) | Cost of Service Before Deficit and Revenue Credit Allocation ($) | Revenue Credit ($) | Deficit ($) | Revenue Requirement After Deficit and Revenue Credit Allocation (Col.3+4+5) ($) | Revenue to Cost Coverage (Col.2/3) |
| | **L'Anse au Loup** | | | | | | |
| 1 | 1.1 Domestic | 574,845 | 1,574,833 | | (999,988) | 574,845 | 0.37 |
| 2 | 1.12 Domestic All Electric | 1,386,524 | 3,564,171 | | (2,177,647) | 1,386,524 | 0.39 |
| 3 | 2.1 General Service 0-100 kW | 831,070 | 1,808,078 | | (977,008) | 831,070 | 0.46 |
| 3 | 2.3 General Service 110-1,000 kVa | 320,673 | 648,639 | | (327,966) | 320,673 | 0.49 |
| 4 | 4.1 Street and Area Lighting | 19,166 | 46,349 | | (27,183) | 19,166 | 0.41 |
| 5 | **Total L'Anse Au Loup** | **3,132,278** | **7,642,071** | | **(4,509,793)** | **3,132,278** | **0.41** |

**NEWFOUNDLAND AND LABRADOR HYDRO**
**2019 Expected Supply Test Year Cost of Service Study - October 26, 2018 Update**
**Labrador Interconnected**
**Comparison of Revenue & Allocated Revenue Requirement**

| Line No. | 1<br>Rate Class | 2<br>Revenues<br>($) | 3<br>Cost of Service Before Deficit and Revenue Credit Allocation<br>($) | 4<br>Revenue Credit<br>($) | 5<br>Deficit Allocation<br>($) | 6<br>Revenue Requirement After Deficit and Revenue Credit Allocation (Col.3+4+5)<br>($) | 7<br>Revenue to Cost Coverage (Col.2/7) |
|---|---|---|---|---|---|---|---|
| | **Labrador Interconnected** | | | | | | |
| 1 | Labrador Industrial Firm | 5,579,486 | 5,582,412 | | - | 5,582,412 | 1.00 |
| 2 | Labrador Industrial Non-Firm | - | - | | - | - | - |
| 3 | **Subtotal Industrial** | **5,579,486** | **5,582,412** | **-** | **-** | **5,582,412** | |
| 4 | CFB - Goose Bay Secondary | - | - | - | - | - | - |
| | **Rural** | | | | | | |
| 5 | 1.1 Domestic | 98,006 | 204,808 | - | 32,422.18 | 237,230 | 0.41 |
| 6 | 1.1A Domestic All Electric | 10,689,208 | 10,779,538 | - | 1,706,460 | 12,485,998 | 0.86 |
| 7 | 2.1 General Service 0-10 kW | 364,304 | 355,560 | - | 56,287 | 411,847 | 0.88 |
| 8 | 2.2 General Service 10-100 kW | 2,258,239 | 1,720,114 | - | 272,303 | 1,992,417 | 1.13 |
| 9 | 2.3 General Service 110-1,000 kVa | 3,751,878 | 2,465,197 | - | 390,254 | 2,855,452 | 1.31 |
| 10 | 2.4 General Service Over 1,000 kVa | 4,146,804 | 2,884,786 | - | 456,678 | 3,341,464 | 1.24 |
| 11 | 4.1 Street and Area Lighting | 361,265 | 291,353 | - | 46,123 | 337,476 | 1.07 |
| 12 | **Subtotal Rural** | **21,669,705** | **18,701,356** | **-** | **2,960,527** | **21,661,883** | |
| 13 | **Total Labrador Interconnected** | **27,249,191** | **24,283,768** | **-** | **2,960,527** | **27,244,296** | |

**NEWFOUNDLAND AND LABRADOR HYDRO**
**2019 Expected Supply Test Year Cost of Service Study - October 26, 2018 Update**
**Total System**
**Rural Deficit Allocation**

| Line No. | 1 | 2 | | |
|---|---|---|---|---|
| | | Deficit Allocation<br>Allocated on<br>Revenue Requirment<br>($) | | |
| | ALLOCATION OF DEFICIT: | | | |
| 1 | Island Interconnected | 62,835,316 | | |
| 2 | Labrador Interconnected | 2,960,527 | | |
| 3 | **Allocated Totals** | **65,795,844** | | |
| | CUSTOMER DEFICIT ALLOCATION: | | | |
| | | Amount | Revenue Requirement | Percent |
| | **Island Interconnected:** | | | |
| 4 | Newfoundland Power | 62,835,316 | 396,924,408 | 95.5% |
| | **Labrador Interconnected:** | | | |
| 5 | Rural Labrador Interconnected | 2,960,527 | 18,701,356 | 4.5% |
| 6 | **Total** | **65,795,844** | | 100.0% |

**NEWFOUNDLAND AND LABRADOR HYDRO**
**2019 Expected Supply Test Year Cost of Service Study - October 26, 2018 Update**
**Unit Demand, Energy & Customer Amounts**

| | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | Rate Class | Before Deficit and Revenue Credit Allocation | | | | | After Deficit and Revenue Credit Allocation | | | | |
| Line No. | | Demand Demand ($/kW) | Non-Demand ($/kWh) | Energy ($/kWh) | Non-Demand Demand & Energy ($/kWh) | Customer ($/Bill) | Demand Demand ($/kW) | Non-Demand ($/kWh) | Energy ($/kWh) | Non-Demand Demand & Energy ($/kWh) | Customer ($/Bill) |
| | **Island Interconnected** | | | | | | | | | | |
| 1 | Newfoundland Power | 12.40 | - | 0.03523 | - | 287,768.97 | 14.36 | - | 0.04081 | - | 333,324.38 |
| 2 | Industrial - Firm | 10.90 | - | 0.03521 | - | 5,165.28 | 10.90 | - | 0.03521 | - | 5,165.28 |
| 3 | Industrial - Non-Firm | - | - | - | - | - | - | - | - | - | - |
| | **Rural** | | | | | | | - | - | | |
| 4 | 1.1 Domestic | - | 0.12133 | 0.03905 | 0.16037 | 40.80 | - | - | - | - | - |
| 5 | 1.12 Domestic All Electric | - | 0.10849 | 0.03913 | 0.14761 | 40.88 | - | - | - | - | - |
| 6 | 1.3 Special | - | 0.16173 | 0.03869 | 0.20042 | 40.43 | - | - | - | - | - |
| 7 | 2.1 General Service 0-10 kW | 31.02 | - | 0.03926 | - | 57.38 | - | - | - | - | - |
| 8 | 2.2 General Service 10-100 kW | - | - | - | - | - | - | - | - | - | - |
| 9 | 2.3 General Service 110-1,000 kVa | 23.22 | - | 0.03940 | - | 73.49 | - | - | - | - | - |
| 10 | 2.4 General Service Over 1,000 kVa | 20.51 | - | 0.03881 | - | 73.53 | - | - | - | - | - |
| 11 | 4.1 Street and Area Lighting | - | 0.12657 | 0.03927 | 0.16585 | 66.35 | - | - | - | - | - |

# Appendix E

Projected 2019 Industrial Customer RSP Current Plan Adjustment

# Newfoundland and Labrador Hydro
## Rate Stabilization Plan Recovery Adjustment
## Island Industrial Customers

| Line No | Calculation of Industrial Customer RSP Rate | | Amount | Comments |
|---|---|---|---|---|
| | Current Plan | | | |
| 1 | December Balance | $ | 1,825,402 | Forecast December RSP 2018[(1)] |
| 2 | Forecast Financing Costs to December 31, 2019 | $ | 64,433 | Line 22 |
| 3 | Total | $ | 1,889,835 | Line 1 plus Line 2 |
| 4 | 12 months to date (Jan - Dec) Industrial Customer Sales (kWh)[1] | | 605,556,124 | |
| 5 | **Total RSP Recovery Adjustment rate (¢ per kWh)** | | **0.312** | Line 3/Line 4*100 |

### Industrial Customer Forecast Financing Charges
### 2019

| | |
|---|---|
| 2015 Test Year Weighted Average Cost of Capital per annum | 6.610% |
| Nominal Financing Rate | 6.418% |

| Line No | | Sales 2018 kWh | Financing Costs | Adjustment | Total To Date Balance |
|---|---|---|---|---|---|
| 6 | Balance Forward | | | | 1,825,402 |
| 7 | January | 54,470,202 | 9,763 | (169,947) | 1,665,218 |
| 8 | February | 49,402,452 | 8,906 | (154,136) | 1,519,989 |
| 9 | March | 53,578,084 | 8,129 | (167,164) | 1,360,954 |
| 12 | April | 54,863,007 | 7,279 | (171,173) | 1,197,061 |
| 13 | May | 37,722,774 | 6,402 | (117,695) | 1,085,768 |
| 14 | June | 45,270,006 | 5,807 | (141,242) | 950,333 |
| 16 | July | 51,464,384 | 5,083 | (160,569) | 794,846 |
| 17 | August | 44,843,150 | 4,251 | (139,911) | 659,187 |
| 18 | September | 55,442,065 | 3,526 | (172,979) | 489,733 |
| 19 | October | 52,000,000 | 2,619 | (162,240) | 330,112 |
| 20 | November | 52,300,000 | 1,766 | (163,176) | 168,702 |
| 21 | December | 54,200,000 | 902 | (169,104) | 500 |
| 22 | Total | 605,556,124 | 64,433 | (1,889,335) | |

[1] Includes forecast sales for the months of October to December

# Appendix F

Projected Industrial Customer Rate Impacts – January 1, 2019

**Newfoundland and Labrador Hydro**
**2019 Required Increase in Customer Billings – Expected Supply Scenario**
**Island Industrial Customers - January 1, 2019 Implementation**

| | 2019 Test Year Billing Units | Unit | 2018 Interim Rates | 2019 Billings at Existing Rates ($) | 2019 Interim Rates[1] | Forecast 2019 Billings ($) | Change ($) | Change (%) |
|---|---|---|---|---|---|---|---|---|
| Demand (kWs) | 1,158,000 | $/kW/mo | 9.95 | 11,522,100 | 10.90 | 12,623,422 | | |
| Energy - Firm (MWhs) | 743,300 | ¢/kWh | 3.971 | 29,516,443 | 3.521 | 26,171,714 | | |
| Spec. Assigned | | $ | 768,935 | 768,935 | 309,917 | 309,917 | | |
| **Total Base Rate** | | | | **41,807,478** | | **39,105,053** | | **-6.8%** |
| RSP: Current Plan | 743,300 | ¢/kWh | (0.285) | (2,118,405) | 0.312 | 2,319,096 | | |
| RSP: Current Plan Mitigation | 743,300 | ¢/kWh | - | - | | - | | |
| RSP: Fuel Rider | 743,300 | ¢/kWh | (0.024) | (178,392) | | - | | |
| CDM Recovery Adjustment | 743,300 | ¢/kWh | 0.010 | 74,330 | 0.010 | 74,330 | | |
| **Total** | | | | **39,585,011** | - | **41,498,479** | **1,913,468** | **4.8%** |

[1] Based on rates proposed to be effective Jan 1, 2019.

**Newfoundland and Labrador Hydro**
**2019 Required Increase in Customer Billings – Expected Supply Scenario**
**Praxair - January 1, 2019 Implementation**

| | 2019 Test Year Billing Units | Unit | 2018 Interim Rates[1] | 2019 Billings at Existing Rates ($) | 2019 Interim Rates[1] | Forecast 2019 Billings ($) | Change ($) | Change (%) |
|---|---|---|---|---|---|---|---|---|
| Demand (kWs) | 72,000 | $/kW/mo | 9.95 | 716,400 | 10.90 | 784,876 | | |
| Energy - Firm (MWhs) | 50,800 | ¢/kWh | 3.971 | 2,017,268 | 3.521 | 1,788,676 | | |
| Spec. Assigned | | $ | - | - | | - | | |
| **Total Base Rate** | | | | **2,733,668** | | **2,573,552** | | **-6.2%** |
| RSP: Current Plan | 50,800 | ¢/kWh | (0.285) | (144,780) | 0.312 | 158,496 | | |
| RSP: Current Plan Mitigation | 50,800 | ¢/kWh | - | - | - | - | | |
| RSP: Fuel Rider | 50,800 | ¢/kWh | (0.024) | (12,192) | - | - | | |
| CDM Recovery Adjustment | 50,800 | ¢/kWh | 0.010 | 5,080 | 0.010 | 5,080 | | |
| **Total** | | | | **2,581,776** | | **2,737,128** | **155,352** | **6.0%** |

[1] Based on rates proposed to be effective Jan 1, 2019.

**Newfoundland and Labrador Hydro**
**2019 Required Increase in Customer Billings – Expected Supply Scenario**
**Vale - January 1, 2019 Implementation**

| | 2019 Test Year Billing Units | Unit | 2018 Interim Rates[1] | 2019 Billings at Existing Rates ($) | 2019 Interim Rates[1] | Forecast 2019 Billings ($) | Change ($) | Change (%) |
|---|---|---|---|---|---|---|---|---|
| Demand (kWs) | 624,000 | $/kW/mo | 9.95 | 6,208,800 | 10.90 | 6,802,259 | | |
| Energy - Firm (MWhs) | 393,800 | ¢/kWh | 3.971 | 15,637,798 | 3.521 | 13,865,762 | | |
| Spec. Assigned | | $ | 480,243 | 480,243 | 144,378 | 144,378 | | |
| **Total Base Rate** | | | | **22,326,841** | | **20,812,399** | | **-7.2%** |
| | | | | | | | | |
| RSP: Current Plan | 393,800 | ¢/kWh | (0.285) | (1,122,330) | 0.312 | 1,228,656 | | |
| RSP: Current Plan Mitigation | 393,800 | ¢/kWh | - | - | - | - | | |
| RSP: Fuel Rider | 393,800 | ¢/kWh | (0.024) | (94,512) | - | - | | |
| CDM Recovery Adjustment | 393,800 | ¢/kWh | 0.010 | 39,380 | 0.010 | 39,380 | | |
| **Total** | | | | **21,149,379** | | **22,080,435** | **931,056** | **4.4%** |

[1] Based on rates proposed to be effective Jan 1, 2019.

**Newfoundland and Labrador Hydro**
**2019 Required Increase in Customer Billings – Expected Supply Scenario**
**Corner Brook Pulp and Paper Limited - January 1, 2019 Implementation**

| | 2019 Test Year Billing Units | Unit | 2018 Interim Rates[1] | 2019 Billings at Existing Rates ($) | 2019 Interim Rates[1] | Forecast 2019 Billings ($) | Change ($) | Change (%) |
|---|---|---|---|---|---|---|---|---|
| Demand (kWs) | 72,000 | $/kW/mo | 9.95 | 716,400 | 10.90 | 784,876 | | |
| Energy - Firm (MWhs) | 34,100 | ¢/kWh | 3.971 | 1,354,111 | 3.521 | 1,200,667 | | |
| Spec. Assigned | | $ | - | - | 11,458 | 11,458 | | |
| **Total Base Rate** | | | | **2,070,511** | | **1,997,000** | | **-3.7%** |
| RSP: Current Plan | 34,100 | ¢/kWh | (0.285) | (97,185) | 0.312 | 106,392 | | |
| RSP: Current Plan Mitigation | 34,100 | ¢/kWh | - | - | - | - | | |
| RSP: Fuel Rider | 34,100 | ¢/kWh | (0.024) | (8,184) | - | - | | |
| CDM Recovery Adjustment | 34,100 | ¢/kWh | 0.010 | 3,410 | 0.010 | 3,410 | | |
| **Total** | | | | **1,968,552** | | **2,106,802** | **138,250** | **7.0%** |

[1] Based on rates proposed to be effective Jan 1, 2019.

**Newfoundland and Labrador Hydro**
**2019 Required Increase in Customer Billings – Expected Supply Scenario**
**North Atlantic Refinery Limited - January 1, 2019 Implementation**

| | 2019 Test Year Billing Units | Unit | 2018 Interim Rates[1] | 2019 Billings at Existing Rates ($) | 2019 Interim Rates[1] | Forecast 2019 Billings ($) | Change ($) | Change (%) |
|---|---|---|---|---|---|---|---|---|
| Demand (kWs) | 384,000 | $/kW/mo | 9.95 | 3,820,800 | 10.90 | 4,186,005 | | |
| Energy - Firm (MWhs) | 263,400 | ¢/kWh | 3.971 | 10,459,614 | 3.521 | 9,274,357 | | |
| Spec. Assigned | | $ | 89,293 | 89,293 | 104,051 | 104,051 | | |
| **Total Base Rate** | | | | **14,369,707** | | **13,564,414** | | **-5.9%** |
| RSP: Current Plan | 263,400 | ¢/kWh | (0.285) | (750,690) | 0.312 | 821,808 | | |
| RSP: Current Plan Mitigation | 263,400 | ¢/kWh | - | - | - | - | | |
| RSP: Fuel Rider | 263,400 | ¢/kWh | (0.024) | (63,216) | - | - | | |
| CDM Recovery Adjustment | 263,400 | ¢/kWh | 0.010 | 26,340 | 0.010 | 26,340 | | |
| **Total** | | | | **13,582,141** | | **14,412,562** | **830,421** | **6.1%** |

[1] Based on rates proposed to be effective Jan 1, 2019.

**Newfoundland and Labrador Hydro**
**2019 Required Increase in Customer Billings – Expected Supply Scenario**
**Teck Resources - January 1, 2019 Implementation**

| | 2019 Test Year Billing Units | Unit | 2018 Interim Rates[1] | 2019 Billings at Existing Rates ($) | 2019 Interim Rates[1] | Forecast 2019 Billings ($) | Change ($) | Change (%) |
|---|---|---|---|---|---|---|---|---|
| Demand (kWs) | 6,000 | $/kW/mo | 9.95 | 59,700 | 10.90 | 65,406 | | |
| Energy - Firm (MWhs) | 1,200 | ¢/kWh | 3.971 | 47,652 | 3.521 | 42,252 | | |
| Spec. Assigned | | $ | | 199,399 | 50,030 | 50,030 | | |
| **Total Base Rate** | | | | **306,751** | | **157,688** | | **-49.2%** |
| RSP: Current Plan | 1,200 | ¢/kWh | (0.285) | (3,420) | 0.312 | 3,744 | | |
| RSP: Current Plan Mitigation | 1,200 | ¢/kWh | - | - | - | - | | |
| RSP: Fuel Rider | 1,200 | ¢/kWh | (0.024) | (288) | - | - | | |
| CDM Recovery Adjustment | 1,200 | ¢/kWh | 0.010 | 120 | 0.010 | 120 | | |
| **Total** | | | | **303,163** | | **161,552** | **(141,611)** | **-46.7%** |

[1] Based on rates proposed to be effective Jan 1, 2019.

# Appendix G

Projected Customer Rate Impacts –July 1, 2019

**Newfoundland and Labrador Hydro**
**2019 Required Increase in Customer Billings – Expected Supply Scenario**
**Newfoundland Power - July 1, 2019 Implementation**

| | 2019 Billing Units at 2018 First Block Size | Unit | 2018 Interim Rate (1) | Existing Billings ($) | 2018 Interim Rate | 2019TY Revenue Requirement | 2018 & 2019 Deficiency[2] | Recovery of Deferred Supply Costs | Forecast 2019 Billings ($) | Change ($) | Percent Change Utility |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | (a) | (b) | (c) | (d) | (e) | (f) | (g) | (h) | (i) = (f)+(g)+(h) | (j) = (i)-(d) | (k) = (j)/(d) |
| Demand (kWs) | 15,158,472 | $/kW/mo | 4.75 | 72,002,742 | | | | | | | |
| Energy (MWhs) | 3,000,000 | ¢/kWh | 2.782 | 83,460,000 | | | | | | | |
| Energy (MWhs) | 2,833,600 | ¢/kWh | 10.422 | 295,317,792 | | | | | | | |
| **Total Base Rate** | | | | **450,780,534** | | **459,759,724** | **8,424,246** | **36,039,498** | **504,223,469** | **53,442,935** | |
| RSP Recovery Adjustment-Normal | 5,833,600 | ¢/kWh | (0.296) | (17,267,456) | (0.296) | (17,267,456) | | | | | |
| RSP Fuel Rider | 5,833,600 | ¢/kWh | 0.423 | 24,676,128 | | - | | | | | |
| CDM Recovery Adjustment | 5,833,600 | ¢/kWh | 0.022 | 1,283,392 | 0.022 | 1,283,392 | | | | | |
| **Total** | | | | **459,472,598** | | **443,775,660** | **8,424,246** | **36,039,498** | **488,239,405** | **28,766,807** | 6.3% |
| | | | | | | | | | | End-Consumer Impact[4] | **4.0%** |

[1] Based on rates effective July 1, 2018.
[2] 2018 & 2019 Revenue Deficiency amortized over 20 months.
[3] Newfoundland Power's portion of the $65.4M in deferred supply costs amortized over 20 months.
[4] End-consumer rate impact calculated as 64% of Utility.

**Newfoundland and Labrador Hydro**
**2019 Required Increase in Customer Billings – Expected Supply Scenario**
**Island Industrial Customers - July 1, 2019 Implementation**

| | 2019 Test Year Billing Units | Unit | 2019 Interim Rates[1] | 2019 Billings at Existing Rates ($) | 2019 Final Rates | 2019 Final Billings ($) | Change ($) | Change (%) |
|---|---|---|---|---|---|---|---|---|
| Demand (kWs) | 1,158,000 | $/kW/mo | 10.90 | 12,623,422 | 10.90 | 12,622,200 | | |
| Energy - Firm (MWhs) | 743,300 | ¢/kWh | 3.521 | 26,171,714 | 3.521 | 26,171,593 | | |
| Spec. Assigned | | $ | 309,917 | 309,917 | 309,917 | 309,917 | | |
| Recovery Rider | 743,300 | | | | 0.256 | 1,902,848 | | |
| **Total Base Rate** | | | | **39,105,053** | | **41,006,558** | 1,901,504 | **4.6%** |
| RSP: Current Plan | 743,300 | ¢/kWh | 0.312 | 2,319,096 | 0.312 | 2,319,096 | | |
| RSP: Current Plan Mitigation | 743,300 | ¢/kWh | - | - | - | - | | |
| RSP: Fuel Rider | 743,300 | ¢/kWh | | - | | - | | |
| CDM Recovery Adjustment | 743,300 | ¢/kWh | 0.010 | 74,330 | 0.010 | 74,330 | | |
| **Total** | | | | **41,498,479** | | **43,399,984** | **1,901,504** | **4.6%** |

[1] Based on rates proposed to be effective Jan 1, 2019.

[2] 2018 Revenue Excess and Island Industrial Customer's portion of the $65.4 M amortized over 20 months.

**Newfoundland and Labrador Hydro**
**2019 Required Increase in Customer Billings – Expected Supply Scenario**
**Praxair - July 1, 2019 Implementation**

| | 2019 Test Year Billing Units | Unit | 2019 Interim Rates[1] | 2019 Billings at Existing Rates ($) | 2019 Final Rates | 2019 Final Billings ($) | Change ($) | Change (%) |
|---|---|---|---|---|---|---|---|---|
| Demand (kWs) | 72,000 | $/kW/mo | 10.90 | 784,876 | 10.90 | 784,800 | | |
| Energy - Firm (MWhs) | 50,800 | ¢/kWh | 3.521 | 1,788,676 | 3.521 | 1,788,668 | | |
| Spec. Assigned | | $ | - | - | | - | | |
| Recovery Rider | 50,800 | | | | 0.256 | 130,048 | | |
| **Total Base Rate** | | | | **2,573,552** | | **2,703,516** | | **4.7%** |
| RSP: Current Plan | 50,800 | ¢/kWh | 0.312 | 158,496 | 0.312 | 158,496 | | |
| RSP: Current Plan Mitigation | 50,800 | ¢/kWh | - | - | - | - | | |
| RSP: Fuel Rider | 50,800 | ¢/kWh | - | - | - | - | | |
| CDM Recovery Adjustment | 50,800 | ¢/kWh | 0.010 | 5,080 | 0.010 | 5,080 | | |
| **Total** | | | | **2,737,128** | | **2,867,092** | **129,964** | **4.7%** |

[1] Based on rates proposed to be effective Jan 1, 2019.

[2] 2018 Revenue Excess and Island Industrial Customer's portion of the $65.4 M amortized over 20 months.

**Newfoundland and Labrador Hydro**
**2019 Required Increase in Customer Billings – Expected Supply Scenario**
**Vale - July 1, 2019 Implementation**

| | 2019 Test Year Billing Units | Unit | 2019 Interim Rates[1] | 2019 Billings at Existing Rates ($) | 2019 Final Rates | 2019 Final Billings ($) | Change ($) | Change (%) |
|---|---|---|---|---|---|---|---|---|
| Demand (kWs) | 624,000 | $/kW/mo | 10.90 | 6,802,259 | 10.90 | 6,801,600 | | |
| Energy - Firm (MWhs) | 393,800 | ¢/kWh | 3.521 | 13,865,762 | 3.521 | 13,865,698 | | |
| Spec. Assigned | | $ | 144,378 | 144,378 | 144,378 | 144,378 | | |
| Recovery Amounts | 393,800 | | | | 0.2560 | 1,008,128 | | |
| **Total Base Rate** | | | | **20,812,399** | | **21,819,804** | | **4.6%** |
| RSP: Current Plan | 393,800 | ¢/kWh | 0.312 | 1,228,656 | 0.312 | 1,228,656 | | |
| RSP: Current Plan Mitigation | 393,800 | ¢/kWh | - | - | - | - | | |
| RSP: Fuel Rider | 393,800 | ¢/kWh | | | | | | |
| CDM Recovery Adjustment | 393,800 | ¢/kWh | 0.010 | 39,380 | 0.010 | 39,380 | | |
| **Total** | | | | **22,080,435** | | **23,087,840** | **1,007,405** | **4.6%** |

[1] Based on rates proposed to be effective Jan 1, 2019.

[2] 2018 Revenue Excess and Island Industrial Customer's portion of the $65.4 M amortized over 20 months.

**Newfoundland and Labrador Hydro**
**2019 Required Increase in Customer Billings – Expected Supply Scenario**
**Corner Brook Pulp and Paper - July 1, 2019 Implementation**

| | 2019 Test Year Billing Units | Unit | 2019 Interim Rates[1] | 2019 Billings at Existing Rates ($) | 2019 Final Rates | 2019 Final Billings ($) | Change ($) | Change (%) |
|---|---|---|---|---|---|---|---|---|
| Demand (kWs) | 72,000 | $/kW/mo | 10.90 | 784,876 | 10.90 | 784,800 | | |
| Energy - Firm (MWhs) | 34,100 | ¢/kWh | 3.521 | 1,200,667 | 3.521 | 1,200,661 | | |
| Spec. Assigned | | $ | 11,458 | 11,458 | 11,458 | 11,458 | | |
| Recovery Amounts | 34,100 | | | | 0.2560 | 87,296 | | |
| **Total Base Rate** | | | | **1,997,000** | | **2,084,215** | | **4.1%** |
| RSP: Current Plan | 34,100 | ¢/kWh | 0.312 | 106,392 | 0.312 | 106,392 | | |
| RSP: Current Plan Mitigation | 34,100 | ¢/kWh | - | - | - | - | | |
| RSP: Fuel Rider | 34,100 | ¢/kWh | - | - | - | - | | |
| CDM Recovery Adjustment | 34,100 | ¢/kWh | 0.010 | 3,410 | 0.010 | 3,410 | | |
| **Total** | | | | **2,106,802** | | **2,194,017** | **87,214** | **4.1%** |

[1] Based on rates proposed to be effective Jan 1, 2019.

[2] 2018 Revenue Excess and Island Industrial Customer's portion of the $65.4 M amortized over 20 months.

**Newfoundland and Labrador Hydro**
**2019 Required Increase in Customer Billings – Expected Supply Scenario**
**North Atlantic Refining Limited - July 1, 2019 Implementation**

| | 2019 Test Year Billing Units | Unit | 2019 Interim Rates[1] | 2019 Billings at Existing Rates ($) | 2019 Final Rates | 2019 Final Billings ($) | Change ($) | Change (%) |
|---|---|---|---|---|---|---|---|---|
| Demand (kWs) | 384,000 | $/kW/mo | 10.90 | 4,186,005 | 10.90 | 4,185,600 | | |
| Energy - Firm (MWhs) | 263,400 | ¢/kWh | 3.521 | 9,274,357 | 3.521 | 9,274,314 | | |
| Spec. Assigned | | $ | 104,051 | 104,051 | 104,051 | 104,051 | | |
| Recovery Amounts | 263,400 | | | - | 0.256 | 674,304 | | |
| **Total Base Rate** | | | | **13,564,414** | | **14,238,269** | | **4.7%** |
| RSP: Current Plan | 263,400 | ¢/kWh | 0.312 | 821,808 | 0.312 | 821,808 | | |
| RSP: Current Plan Mitigation | 263,400 | ¢/kWh | - | - | - | - | | |
| RSP: Fuel Rider | 263,400 | ¢/kWh | - | - | - | - | | |
| CDM Recovery Adjustment | 263,400 | ¢/kWh | 0.010 | 26,340 | 0.010 | 26,340 | | |
| **Total** | | | | **14,412,562** | | **15,086,417** | **673,856** | **4.7%** |

[1] Based on rates proposed to be effective Jan 1, 2019.

[2] 2018 Revenue Excess and Island Industrial Customer's portion of the $65.4 M amortized over 20 months.

**Newfoundland and Labrador Hydro**
**2019 Required Increase in Customer Billings – Expected Supply Scenario**
**Teck Resources - July 1, 2019 Implementation**

| | 2019 Test Year Billing Units | Unit | 2019 Interim Rates[1] | 2019 Billings at Existing Rates ($) | 2019 Final Rates | 2019 Final Billings ($) | Change ($) | Change (%) |
|---|---|---|---|---|---|---|---|---|
| Demand (kWs) | 6,000 | $/kW/mo | 10.90 | 65,406 | 10.90 | 65,400 | | |
| Energy - Firm (MWhs) | 1,200 | ¢/kWh | 3.521 | 42,252 | 3.521 | 42,252 | | |
| Spec. Assigned | | $ | 50,030 | 50,030 | 50,030 | 50,030 | | |
| Recovery Amounts | 1,200 | | | | 0.256 | 3,072 | | |
| **Total Base Rate** | | | | **157,688** | | **160,754** | | **1.9%** |
| RSP: Current Plan | 1,200 | ¢/kWh | 0.312 | 3,744 | 0.312 | 3,744 | | |
| RSP: Current Plan Mitigation | 1,200 | ¢/kWh | - | - | - | - | | |
| RSP: Fuel Rider | 1,200 | ¢/kWh | - | - | - | - | | |
| CDM Recovery Adjustment | 1,200 | ¢/kWh | 0.010 | 120 | 0.010 | 120 | | |
| **Total** | | | | **161,552** | | **164,618** | **3,065** | **1.9%** |

[1] Based on rates proposed to be effective Jan 1, 2019.

[2] 2018 Revenue Excess and Island Industrial Customer's portion of the $65.4 M amortized over 20 months.

**Newfoundland and Labrador Hydro**
**2019 Required Increase in Customer Billings - Expected Supply Scenario**
**Remaining Classes - July 1, 2019 Implementation**

| | 2019 Test Year Billing Units | Unit | Existing Average Unit Cost[1] | Existing Billings $ | Projected Average Unit Cost[2] | Revenue Requirement 2019 Cost of Service | 2018 & 2019 Revenue Deficiency (12/20)[5] | Balance owing to customers in accordance with Board Order P.U. 22(2017) | $ Change | Percent Change |
|---|---|---|---|---|---|---|---|---|---|---|
| Rural Labrador Interconnected | 753,796,243 | $/kWh | 0.029 | 21,937,762 | 0.028 | 21,661,883 | (245,740) | (41,184) | (562,803) | **-2.6%** |
| Hydro Rural Government | 2,396,960 | $/kWh | 0.866 | 2,075,306 | 1.051 | 2,393,775 | 126,382 | - | 444,851 | **21.4%** |
| Hydro Rural Other[4] | 486,719,690 | $/kWh | 0.129 | 62,551,580 | 0.134 | 65,057,980 | - | - | 2,506,400 | **4.0%** |
| Labrador Industrial[3] | 3,009,000 | $/kW | 1.61 | 4,844,490 | 1.94 | 5,582,412 | 240,111 | - | 978,033 | **20.2%** |

[1] Average unit revenues expressed in dollars per kWh based on July 1, 2018 rates.
[2] Average unit revenues expressed in dollars per kWh based on 2019 Proposed Final Rates excluding the 2018 & 2019 Revenue Deficiency/(Excess).
[3] Includes both Transmission and Generation Cost Recovery. The unit cost per kW is calculated based on Power on Order.
[4] Percentage increase is 64% of Newfoundland Power's Wholesale increase.
[5] Recovery of Rural Labrador Interconnected and Labrador Industrial forecast to occur over 24 months.

# Appendix H

Revised 2017 General Rate Application Part B, Hydro's Proposals

**Newfoundland and Labrador Hydro**
**2017 General Rate Application**
**Proposals Updated to Reflect Settlement Agreements and Schedule 1, Evidence**

## B. Hydro's Proposals:

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

<u>Revenue Requirement</u>

(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); ~~and~~ agreed to in section 18 of the Supplemental Settlement Agreement dated July 16, 2018, to be approved, effective January 1, 2018; and updated in Appendix I of Hydro's filing of November 14, 2018;

(4) ~~the transfer to the Revised Energy Supply Variance Deferral Account of all 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 TFAs, be approved; and~~ that 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 TFAs be excluded from the calculation of Hydro's 2018 and 2019 Test Year revenue requirements;

(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 5.66% in a range of 5.46% to 5.86% 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) a rate of return on rate base of 5.62% in a range of 5.42% to 5.82% 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 a weighted average cost of capital of 5.66%, be approved; and

b) that Hydro's forecast capital structure for 2019, as set out in Chapter 4 of the evidence in support of this Application, with a weighted average cost of capital of 5.62%, 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. 18(2016) 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 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 a No. 6 fuel cost of $64.41 per barrel and a conversion rate of 618 kWh per barrel, 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 excess earnings account definition, as agreed to in section 23 of the Settlement Agreement dated April 11, 2018, be approved;

(24) 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;

(25) 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;

(26) that the MF-HV 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

(27) 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;

(28) 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;

(29) 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;

(30) that the functionalization of TL267 as 100% demand, as agreed to in section 7(d) of the Supplemental Settlement Agreement dated July 16, 2018, be approved;

(31) 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;

(32) 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;

<u>2019 Rate Proposals</u>

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

(34) 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;

(35) 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;

(36) 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;

(37) 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;

(38) 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;

(39) 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 kWh; 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 |

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

(41) 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;

(42) 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;

(43) 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.

<u>Deferred Supply Costs</u>

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

g) 2015 Isolated Systems Supply Cost Variance Deferral Account balance of $0.00;

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

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

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

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

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

m) 2015 Holyrood Conversion Rate Deferral Account debit balance of $3,582,048.00;

n) 2016 Holyrood Conversion Rate Deferral Account debit balance of $2,150,665.00;

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

(45) 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;

(46) 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.

(47) 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;

(48) 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;

(49) 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;

<u>Rules and Regulations</u>

(50) 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;

(51) 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,

(52) 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.

# Appendix I

Revised Energy Supply Variance Deferral Account

## Newfoundland and Labrador Hydro
## Revised Energy Supply Cost Variance Deferral Account[1]

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

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

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

Variations resulting from both the price and volume of off-island power purchases, including delivery costs, shall be charged or credited to this account.

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

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

***Energy Supply costs*** will be determined by the following formula:

$$A + B + C + D$$

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

Where:

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

[1] The Energy Supply Cost Variance Account Definition has been updated to reflect changes required for the November 9, 2018 submission of the “2018 Cost Deferral and Interim Rates Application,” Revision 2. Shading reflects updates made to the definition since it was last filed with the Board of Commissioners of Public Utilities as “Appendix L – Energy Supply Cost Variance Account Definition – Expected Supply Scenario,” *2017 GRA Additional Cost of Service Information in Compliance with Order No. P.U. 2(2018)* on March 22, 2018.

B = Test Year Off-Island Power Purchase Variances resulting from both price and volume;

Where:

A = (Actual Off-Island Power Purchase Cost – Test Year Off-Island Power Purchase Cost)

"Actual Off-Island Power Purchase Cost" shall not include any expenditure related to use of the Labrador-Island Link or use of the Labrador Transmission Assets under the Interim Transmission Funding Agreements.

C = Test Year Power Purchase Variances resulting from volume;

Where:

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

D = Fuel costs or savings resulting from the variance in generation at the Holyrood Thermal Generating Facility (Holyrood TGS);

Where:

D = E/F x G

E = Holyrood TGS Test Year average annual fuel cost per barrel;

F = Test Year fuel conversion factor (kWh/bbl); and

G = [(Test Year kWh Thermal Generation + Test Year kWh Power Purchases) - (Actual kWh Thermal Generation + Actual kWh Power Purchases)] for all defined sources.

Actual Off-Island Power Purchases shall be based upon delivered kWh, net of transmission losses.

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

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

# 2018 Cost Deferral Evidence

October 26, 2018
Revised November 14, 2018

*A Report to the Board of Commissioners of Public Utilities*

newfoundland labrador hydro
a nalcor energy company

## Table of Contents

## 1.0 Introduction

On July 28, 2017, Newfoundland and Labrador Hydro (Hydro) filed its 2017 General Rate Application (GRA) requesting, among other things, approval of customer rates reflecting 2018 and 2019 Test Year costs which reflected a proposed change in depreciation methodology. In a Settlement Agreement dated April 11, 2018 (the Settlement Agreement), the Parties agreed to the use of the revised depreciation methodology for the 2018 and 2019 Test Years, amongst other things.[1]

As a result of delays in the 2017 GRA, Hydro anticipates that its conclusion is unlikely to occur in 2018. In the absence of a final 2017 GRA Order in 2018, Hydro will be required to continue to account for its 2018 Depreciation Expense[2] in accordance with its existing methodology. If Hydro were to apply the existing depreciation methodology, it forecasts that it will incur an additional $15.0 million in Depreciation Expense when compared to the methodology proposed in the 2017 GRA and agreed to by the Parties in the Settlement Agreement.[3]

This 2018 Cost Deferral and Interim Rates Application includes a proposal to establish a 2018 Cost Deferral Account to provide Hydro the opportunity to earn a return for 2018 which is inside the projected 2018 Test Year range of return on rate for 2018.

## 2.0 Requirement for 2018 Cost Deferral

Hydro applied for, and was granted, 2018 interim rate increases for both Island Industrial Customers and Newfoundland Power effective April 1 and July 1, 2018, respectively.[4] Hydro's interim rates applications were based on the expectation that a 2017 GRA Order would be issued in 2018. Approval of interim rates provided recovery of a portion of Hydro's increased cost of service for 2018 relative to existing rates. The recovery levels sought in these

[1] 2017 GRA, Exhibit 11, Depreciation Study.
[2] Depreciation Expense includes depreciation expense, loss on disposal, disposal proceeds, and removal costs.
[3] Settlement Agreement dated April 16, 2018, item number 9 states *"With respect to Depreciation Expense the following, which results in reductions in the 2018 and 2019 Test Years' revenue requirements of approximately $10.1 million and $8.9 million, respectively…"*
[4] Board Order No's P.U. 7(2018) and P.U. 15(2018), respectively.

applications were based on Hydro's 2018 Test Year costs, including a decrease in Depreciation Expense which was computed based on the proposed depreciation methodology from the 2017 GRA.

In the absence of a 2017 GRA Order in 2018, Hydro forecasts that it will be required to record an additional $15.0 million in 2018 due to depreciation methodology that was not contemplated in the approval of interim rates for Newfoundland Power in 2018.[5] Forecast revenues from current rates (including the increased revenues from interim rate changes in 2018) will not recover enough revenue to provide Hydro the opportunity to earn a reasonable return on rate base as a result of the unanticipated requirement to use the existing depreciation methodology in 2018.

The 2018 cost deferral requested in this application reflects the expense differential between Hydro's current Depreciation Expense methodology and the 2017 GRA depreciation methodology reflected in the Settlement Agreement of April 11, 2017.

## 3.0 Return on Rate Base

Hydro's currently approved rate of return on rate base is 6.61% as approved in Order No. P.U. 22(2017) however, Hydro's 2017 GRA as filed requested approval of a 2018 Test Year return on rate base of 5.73%. Due to the material reduction in return on rate base requested in the 2017 GRA, Hydro is proposing a cost deferral for 2018 to provide the opportunity to earn a rate of return based on the reduced rate of return requirement forecast for the 2018 Test Year.

Hydro's 2018 Test Year in its original 2017 GRA filing forecast a required return on rate base of 5.73% based on 2018 forecast interest expense of $94.8 million. Hydro's most recent forecast of 2018 interest expense is $90.6 million, a decrease of approximately $4.2 million. This

[5] The Utility interim rates application filed on April13, 2018 reflected the approximate $10.1 million in depreciation savings noted in the 2017 GRA Settlement Agreement signed on April 11, 2018.

variance is due to a number of factors including, but not limited to, change in forecast interest rates, timing of debt issuances, and amount of long-term debt issued.

The revised forecast cost of debt for 2018 reduces Hydro's calculation of the 2018 Test Year forecast rate of return on rate base. Based on the updated forecast cost of debt, Hydro projects that its revised 2018 Test Year rate of return on rate base would equal approximately 5.45%. Given the materiality of this change, Hydro considers it appropriate to update its rate of return on rate base and average rate base calculations in its 2017 GRA Compliance Application.

## 4.0 2018 Financial Projections

As of the date of this filing, Hydro's forecast net income at the end of 2018 is expected to be approximately $9.9 million,[6] with a forecast rate of return on rate base of 4.63% and a forecast rate of return on equity of 3.13%. The forecast rate of return on rate base is materially below the 5.25% bottom of the projected range of rate of return on rate base for the 2018 Test Year.

Should the Board approve the proposed 2018 Cost Deferral, currently forecast to be approximately $15.0 million, Hydro's forecast return on rate base would increase to 5.28%, 3 basis points above the bottom of the projected range of rate of return on rate base for the 2018 Test Year. A summary of these forecasts are provided in Table 1.

**Table 1**
**2018 Forecast Financial Results**

| Particulars | Excluding 2018 Cost Deferral | Including Proposed 2018 Cost Deferral |
|---|---|---|
| Net Income ($000s) | 9,973 | 24,961 |
| Rate of Return on Equity | 3.13% | 7.68% |
| Rate of Return on Rate Base | 4.63% | 5.28% |
| | | |
| Revised Bottom of Range | 5.25% | 5.25% |
| Variance from Bottom of Range | -0.62% | 0.03% |

[6] See Appendix A to this Evidence.

Appendix A to this evidence provides Hydro's forecast financial results for 2018.

## 5.0 Conclusion

Hydro's interim rates applications were based on the expectation that a 2017 GRA Order would be issued in 2018. In the absence of a 2017 GRA Order by the end of 2018, Hydro will have to record 2018 Depreciation Expense based on its existing approved methodology and not the depreciation methodology provided for in the Settlement Agreement. The forecast impact of this change in methodology is an additional $15.0 million in Depreciation Expense for 2018. Hydro projects that the additional Depreciation Expense will reduce Hydro's 2018 net income such that it will not have the opportunity to earn a just and reasonable return in 2018.

The revised depreciation methodology was agreed to by the parties in the Settlement Agreement. Hydro considers it reasonable that the cost differential between the existing depreciation methodology and depreciation methodology reflected in the 2017 GRA Settlement Agreement be approved as a cost deferral for 2018.

The proposed 2018 cost deferral is not a request for pre-approval of a change in the depreciation methodology in advance of the 2017 GRA Order; rather, Hydro is proposing a 2018 cost deferral to be calculated as the differential between the existing and proposed depreciation methodologies for 2018 year-end financial reporting purposes only, with recovery subject to the Board's final GRA Order.

Approval of the requested 2018 Cost Deferral would provide Hydro the opportunity to earn a 2018 rate of return on rate base of 5.28% (i.e., 3 basis points above the bottom of the projected range of rate of return on rate base for the 2018 Test Year). Approval of the proposed cost deferral for 2018 will have no impact on customer rates, but will provide Hydro the opportunity to earn a reasonable rate of return in 2018.

The actual amount of the 2018 cost deferral will be determined in preparing Hydro's 2018 year-end financial results. The proposed 2018 Cost Deferral Account definition is included as Schedule 3 to the 2018 Cost Deferral and Interim Rates Application.

# Appendix A

2018 Forecast Financial Results

**Newfoundland and Labrador Hydro**
**2018 Forecast Financial Results**

| Line No. | | Existing 2018 Forecast ($000s) | 2018 Cost Deferral Forecast ($000s) | Revised 2018 Forecast ($000s) |
|---|---|---|---|---|
| | **REVENUE** | | | |
| 1 | Energy sales | 557,655 | - | 557,655 |
| 2 | Other revenue | 5,831 | - | 5,831 |
| 3 | | 563,486 | - | 563,486 |
| | **EXPENSES** | | | |
| 4 | Operating costs | 137,637 | - | 137,637 |
| 5 | Other (income) and expense | 9,155 | (15,019) | (5,863) |
| 6 | Foreign Exchange | 2,589 | - | 2,589 |
| 7 | Fuels | 154,779 | - | 154,779 |
| 8 | Power purchased | 73,403 | - | 73,403 |
| 9 | Amortization | 85,028 | - | 85,028 |
| 10 | ARO Accretion | 362 | - | 362 |
| 11 | Interest | 90,589 | - | 90,589 |
| 12 | | 553,543 | (15,019) | 538,524 |
| 13 | **NET INCOME** | **9,943** | **15,019** | **24,961** |
| 14 | **Rate of Return on Rate Base** | **4.63%** | | **5.28%** |
| 15 | Projected Compliance Rate of Return Range: | | | |
| 16 | Upper end of the range: 5.45% + 0.20% | 5.65% | | 5.65% |
| 17 | Lower end of the range: 5.45% - 0.20% | 5.25% | | 5.25% |
| 18 | **Financial Return on Equity** | **3.13%** | | **7.68%** |

**Newfoundland and Labrador Hydro**
**2018 Cost Deferral Account Definition**

This account shall be charged based upon the following formula:

**A = B – C**

Where:

**A** = The amount to be deferred.

**B** = 2018 depreciation, loss on disposal, disposal proceeds, and removal costs calculated in accordance with Hydro's Board approved depreciation methodology.

**C** = 2018 depreciation, loss on disposal, disposal proceeds, and removal costs calculated in accordance with the depreciation methodology settled through the 2017 General Rate Application.

Disposition of any balance in this account shall be subject to a future order of the Board.

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

**AND IN THE MATTER OF** a General Rate Application by Newfoundland and Labrador Hydro ("Hydro") filed on July 28, 2017, as revised;

**AND IN THE MATTER OF** an application by Hydro for approval of: ~~(i) deferral of the operating and maintenance ("O&M") costs required to be paid by Hydro for use of the Labrador-Island Link ("LIL") and Labrador Transmission Assets ("LTA") prior to full commissioning of the Muskrat Falls Project;~~ (i~~i~~) a 2018 cost deferral account to provide Hydro the opportunity to earn a reasonable return on rate base in 2018 pursuant to Section 80 of the *Act*; and (ii~~i~~) an application by Hydro, pursuant to Sections 70 and 75 of the *Act,* for the approval of Island Industrial Customer electricity rates to become effective January 1, 2019 on an interim basis (2018 Cost Deferral and Interim Rates Application).

## AFFIDAVIT

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

1. I am Director, Regulatory Affairs, of Newfoundland and Labrador Hydro, the Applicant named in the attached Application.
2. I have read and understand the foregoing Application.
3. I have personal knowledge of the facts contained therein, except where otherwise indicated, and they are true to the best of my knowledge, information and belief.

**SWORN** at St. John's in the Province of Newfoundland and Labrador, this 14 day of November 2018, before me:

Barrister – Newfoundland and Labrador

Kevin J. Fagan