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August 3, 2018

Via Email & Courier

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

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

Dear Ms. Blundon:

Re: 2017 General Rate Application (GRA) – Supplemental Evidence – Customer Impacts Reflecting 2017 GRA Settlement Agreements (Revision 1)

Enclosed with this letter please find one (1) original plus thirteen (13) copies of Supplemental Evidence – Customer Impacts Reflecting the 2017 GRA Settlement Agreements (Revision 1).

The revisions are found on pages 3, 13, 14, 23 and Schedule 5, page 3 of 3. All revisions have been shaded grey for ease of reference.

If you have any questions, please contact the undersigned.

Yours truly,

NEWFOUNDLAND AND LABRADOR HYDRO

Michael S. Ladha
Legal Counsel & Assistant Corporate Secretary
MSL/sk

cc: Gerard Hayes - Newfoundland Power
Paul Coxworthy - Stewart McKelvey
Denis J. Fleming - Cox & Palmer
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ecc: Van Alexopoulos - Iron Ore Company
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Supplemental Evidence

Customer Impacts Reflecting
2017 GRA Settlement Agreements

July 20, 2018
Revised August 3, 2018

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1.0 Background

On July 16, 2018, the Parties entered into a Supplemental Settlement Agreement which, in combination with the Settlement Agreement dated April 11, 2018, resolved a number of 2017 General Rate Application (GRA) matters.

In its 2017 GRA Compliance filing, 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 agreements and the decisions to be made by the Board in its 2017 GRA Order.

The most material revenue requirement differences between Hydro's 2017 GRA filing and the revenue requirement estimates reflecting the settlement agreements relate to the use of the Expected Supply Scenario[1] in determining Hydro's supply costs for each test year. This evidence also provides estimated customer impacts by class reflecting:

- The settlement agreements;
- The recovery of the 2015 to 2017 deferred energy supply costs for the Island Interconnected System;
- The estimated 2018 revenue deficiencies (or excess revenues) by class; and
- The ongoing delay in the conclusion of the regulatory process in considering the proposed project providing for the transmission line interconnection from Muskrat Falls to Happy Valley.

For the purpose of providing additional context, this evidence also provides information on potential customer rate increases upon full commissioning of the Muskrat Falls Project.[2]

[1] Hydro initially provided information on the Expected Supply Scenario on March 22, 2018 in compliance with Board Order No. P.U. 2(2018).

[2] Muskrat Falls Project refers to the Labrador-Island Link (LIL), the Labrador Transmission Assets (LTA), and the Muskrat Falls Generating Station.

2.0 Off-Island Purchases

2.1 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. Other off-island purchases include short-term economic purchases, such as those which have occurred year to date, as well as firm, longer-term contracted purchases which are forecast to commence this fall. Purchases are delivered over both the Maritime Link and the Labrador-Island Link (LIL).

2.2 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)[3]

Supply Source	2018	2019
Recapture Energy	493	920
Other Off-Island Purchases[4]	113	96
Total	**606**	**1,016**

Table 2 provides Hydro's projected costs associated with off-island purchases for 2018 and 2019.

[3] 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.

[4] For confidentiality purposes, this evidence does not provide a breakdown of the off-island purchases.

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

Supply Source	2018	2019
Recapture Energy[5]	1,140	2,118
Other Off-Island Purchases	13,690	10,046
LIL and LTA Operating and Maintenance	8,365	51,400
Total	23,195	63,564

2.3 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,[6] partially offset by the cost of off-island power purchases.[7]

To access off-island power purchases, Hydro will enter into agreements with the owners of the LIL and the Labrador Transmission Assets (LTA) which will permit Hydro to use those transmission facilities to transmit energy to the island and require Hydro to pay the operating and maintenance costs associated with the use of the transmission lines.[8] Hydro is proposing that, consistent with Order-in-Council OC2013-343, the operating and maintenance costs incurred to use the LIL and the LTA prior to full commissioning of the Muskrat Falls Project be included for recovery in Hydro's 2018 and 2019 Test Years. Hydro's 2018 and 2019 Test Year costs would also include supply costs related to the purchase of Recapture Energy and costs incurred to achieve power purchases from other jurisdictions.

[5] Hydro has a contract in place with CF(L)Co to purchase Recapture Energy at a cost of 0.2 cents per kWh.
[6] No. 6 fuel savings are achieved as a result of reduced fuel consumption at the Holyrood Thermal Generating Station.
[7] Total cost of power purchases include the energy purchase costs, delivery costs incurred to obtain off-island supply (including agency fees) and the operating and maintenance costs required to be paid by Hydro for access to the LIL and the LTA.
[8] The operating and maintenance costs associated with the LIL and the LTA in the 2018 and 2019 Test Year revenue requirements are $8.4 million and $51.4 million, respectively. Hydro is required to pay these costs for the use of the LIL and the LTA to provide savings in Holyrood fuel costs during the pre-commissioning period. Also, under open access requirements, Hydro will be required to pay a transmission tariff which will include these costs once testing has been completed for these assets.

In its 2017 GRA filing, Hydro proposed that the Rate Stabilization Plan (RSP) operate in 2018 based on the 2015 Test Year and in 2019 based on the 2019 Test Year.[9] 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 excess revenues) 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).

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. Hydro's calculations of the 2018 Test Year fuel cost savings are shown in Schedule 1.

A similar approach is required for 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 Accounts.[10] Therefore, in order to avoid duplication of fuel cost recovery through 2018 revenue deficiencies and balances accumulating in the Supply Cost Variance Accounts, Hydro must base the gas turbine and diesel costs for the 2018 Test Year on 2015 Test Year fuel prices for computing revenue deficiency/excess revenues for the 2018 Test Year.[11]

In its 2017 GRA filing, Hydro proposed that the RSP operate in 2019 based on the 2019 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 $85.55 per barrel.[12] While the $85.55 may not be the fuel forecast used for the 2017

[9] See Hydro's August 23, 2017 correspondence to the Board in response to the Board's August 14, 2017 request for further information on the 2017 GRA filing.
[10] Energy Supply Cost Variance Deferral Account, Isolated Systems Supply Cost Variance Deferral Account, and the Holyrood Conversion Rate Deferral Account.
[11] For the 2019 Test Year, Hydro has forecast approximately 27.5 GWh in gas turbine and black start diesel generation.
[12] Based on March 2018 PIRA fuel forecast.

GRA Compliance filing, Hydro has used this fuel price in this evidence to estimate its 2019 Test Year revenue requirement. Hydro has also used a No. 6 fuel price of $85.55 per barrel to calculate the savings from off-island purchases for the 2019 Test Year.[13]

In Schedule 1 to this evidence, Hydro has computed projected 2018 Test Year No. 6 fuel savings from off-island purchases to be $67.4 million. Projected 2019 Test Year No. 6 fuel savings are expected to be $149.1 million.[14]

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	$67,367	$149,089
Less: Projected Costs of Off-Island Purchases	($23,195)	($63,564)
Net Savings from Off-Island Purchases	**$44,172**	**$85,525**

Hydro notes that the forecast net savings from off-island purchases are approximately $31.9 million and $10.2 million higher for 2018 and 2019, respectively, than included in the previous estimates provided to the Board.[15] The key driver of the increase in net savings for 2018 is the reduction of $18.9 million[16] in operating and maintenance costs for the LIL and the LTA due to a delay in the LIL in-service date. For 2019, there is an increase in forecast net savings due to an increase in off-island purchases over the LIL.

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

[14]

Reduced Holyrood Generation (MWh)	(A)	1,016,000
Holyrood Conversion Factor (kWh/bbl)	(B)	583
Reduced No. 6 barrels (bbls)	(C) =(A/B) x 1,000	1,742,710
Cost per barrel ($/bbl)	(D)	$85.55
Total ($000s)	(E) = (D x C)/1,000	$149,089

[15] Hydro's response to NP-NLH-115 - Revision 1 shows a net savings from off-island purchases of $12.3 million in 2018 and $75.3 million in 2019.

[16] Hydro's response to NP-NLH-115 - Revision 1 shows 2018 operating costs for the LIL and the LTA of $27.3 million. Hydro is forecasting costs of $8.4 million (Table 2), for projected savings of $18.9 million.

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. Given that the Muskrat Falls Project is forecast to be fully commissioned on September 1, 2020, Hydro anticipates its next GRA filing will include both 2020 and 2021 as test years. The projected savings from off-island purchases in 2020 will be reflected in the calculation of the revenue requirement for the 2020 Test Year.

In Schedule 1 to this evidence, Hydro has computed projected 2018 Test Year No. 6 fuel costs to be $98.7 million. Projected 2019 Test Year No. 6 fuel costs are expected to be $82.5 million.[17]

The Supplemental Settlement Agreement also provides for variances in the forecast Test Year net savings from off-island purchases to be transferred to a Revised Energy Supply Cost Variance Deferral Account.[18] The dispositions of the balances that accrue in this account are subject to a further order of the Board.

2.4 Revenue Requirements

As a result of the timing of the filing of this evidence in relation to the signing of the Supplemental Settlement Agreement, Hydro did not have adequate time to prepare updated revenue requirement schedules reflecting the required adjustments.[19] To estimate the impact of the settlement agreements, Hydro has reflected revenue requirement adjustments updating

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[17]

Holyrood Generation (MWh)	(A)	562,026
Holyrood Conversion Factor (kWh/bbl)	(B)	583
No. 6 barrels (bbls)	(C) =(A/B) x 1,000	964,024
Cost per barrel ($/bbl)	(D)	$85.55
Total ($000s)	(E) = (D x C)/1,000	$82,472

[18] 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.

[19] Hydro will provide updated finance schedules reflecting the settlement agreements and the Board's decisions provided in the 2017 GRA Order in finance schedules to be filed in its 2017 GRA Compliance filing.

its 2018 and 2019 Test Year Cost of Service Studies which were previously filed in the Expected Supply Scenario.

3.0 Cost of Service Results

3.1 General

Hydro has used the cost of service methodology as described in the Supplemental Settlement Agreement in preparing preliminary cost of service study results to determine customer rate projections. Schedules 2 and 3 to his evidence provide the cost of service summary schedules for the 2018 and 2019 Test Years, respectively, reflecting adjustments identified in Table 4.

Table 4: Revenue Requirement Reductions Related to Settlement Agreements ($000s)

Particulars	**2018 Test Year**	**2019 Test Year**
Reduction in Depreciation Expense[20]	10,100	8,900
Increase in vacancy allowance to 55 full time equivalent positions[21]	1,328	1,328
Removal of Business Systems Transformation Project costs[22]	2,540	3,040
Reduction in fee on long-term debt issues[23]	567	672
Reduction in interest costs to reflect borrowing from Government[24]	515	529
Elimination of inventory allowance associated with Holyrood Plant[25]	2,100	2,100
Reduction costs associated with capacity assistance agreements[26]	n/a	600
Total Reduction in Revenue Requirement	**17,150**	**17,169**

In addition, the Expected Supply Scenario provided for in the Supplemental Settlement Agreement requires that the cost of service study revenue requirement reflect the projected net savings from off-island purchases shown in Table 3.

[20] Settlement Agreement, April 16, 2018, Item 9.
[21] Settlement Agreement, April 16, 2018, Item 10. Change of 15 full time equivalents x approximately $88,500 per full time equivalent.
[22] Settlement Agreement, April 16, 2018, Item 11. Further regulatory process required prior to proposal from recovery from customers.
[23] Settlement Agreement, April 16, 2018, Item 12(a)(i).
[24] Settlement Agreement, April 16, 2018, Item 12(a)(ii).
[25] Settlement Agreement, April 16, 2018, Item 21.
[26] Supplemental Settlement Agreement, July 16, 2018, Item 22.

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.

Finally, the cost of service studies also assume the frequency converter asset will remain in service for the 2018 and 2019 Test Years as the transfer of this asset to Corner Brook Pulp and Paper (CBPP) is subject to a separate application.[27]

3.2 Revenue Deficiencies

Table 5 provides a derivation of Hydro's revenue deficiencies/excess revenue for 2018 and 2019 based on the Expected Supply Scenario reflecting the settlement agreements.[28] The revenue deficiencies/excess revenues 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 base rates.[29] The revenue deficiency for 2019 was determined following the same approach; however, existing base rates were used in the calculation for 2019 Test Year revenues.[30] Schedule 4 to this evidence provides the calculations which support Table 5.

[27] The transfer of the frequency converter to CBPP will result in the specifically assigned charge to CBPP reducing to approximately $10,000 per year and an additional $85,000 in operating and maintenance costs allocated to Newfoundland Power. Please refer to Hydro's responses to NP-NLH-003 and PUB-NLH-001 from the CBPP frequency converter transfer application.

[28] Revenue deficiency and excess revenues are calculated by using base rates and exclude charges related to RSP and CDM adjustments.

[29] 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.

[30] Existing rates reflect customer rates as of July 1, 2018.

Table 5: Projected Test Year Revenue Deficiency/Excess by Customer Class ($ millions)[31]

	2018 Test Year			2019 Test Year		
Particulars	**Revenue Forecast[32]**	**Revenue Requirement[33]**	**Revenue Excess/ (Deficiency)**	**Existing Rates**	**Revenue Requirement**	**Revenue Excess/ (Deficiency)**
	(a)	(b)	(c)=(a)-(b)	(d)	(e)	(f)=(d)-(e)
Newfoundland Power	441.5	420.3	21.2	450.8	460.9	(10.1)
Island Industrial	41.5	36.2	5.3	42.7	40.1	2.6
Rural Labrador Interconnected	20.2	20.6	(0.4)	20.2	21.3	(1.1)
Labrador Industrial Transmission	4.7	4.9	(0.2)	4.7	5.6	(0.9)
Hydro Rural Government Diesel	2.1	2.3	(0.2)	2.1	2.4	(0.3)

Table 5 shows that as a result of the savings from off-island purchases in 2018 and the approval of interim rates for Newfoundland Power and Island Industrial Customers, Hydro will have excess revenues from these classes of $21.2 million and $5.3 million, respectively. Hydro will have a 2018 revenue deficiency of $0.4 million from the Hydro Rural Labrador Interconnected class, $0.2 million from the Labrador Industrial Transmission class, and $0.2 million for Hydro Rural Government Diesel Customers.[34]

Based on existing rates, Hydro projects a 2019 Test Year revenue deficiency from Newfoundland Power of $10.1 million and excess revenues from Island Industrial Customers of $2.6 million. Hydro will have a 2019 revenue deficiency of $1.1 million from the Hydro Rural Labrador Interconnected class, $0.9 million from the Labrador Industrial Transmission class under existing rates, and $0.3 million 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 expected

[31] The change in billings provided in Table 5 reflects the elimination of the existing RSP fuel riders in 2019 but reflects no change in the RSP recovery adjustment rates.
[32] 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.
[33] Revenue amounts after allocation of the Rural Deficit.
[34] 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.

2018 Revenue Deficiency to be recovered from Newfoundland Power. However, with the updated forecast savings from off-island purchases, this transfer is not required as excess revenues are forecast for Newfoundland Power for the 2018 Test Year. 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.

3.3 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.[35]

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 6 provides the allocation of the proposed costs to be recovered through the rates of Newfoundland Power and Island Industrial Customers.

[35] The allocation percentage will be based on the RSP energy allocators consistent with the year in which the Approved Deferred Supply Costs were incurred.

Table 6: Allocation of Deferred Supply Costs ($)

Account	Balance	Newfoundland Power	Island Industrial Customers	Labrador Allocation
Isolated Systems Deferral[36]	(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**[37]
Allocation Based on Historical Energy[38]		91.8%	8.1%	0.1%

The Supplemental Settlement Agreement provides that the 2018 revenue deficiency/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. 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 excess revenues.

Table 7 provides the derivation of the estimated monthly charge to apply to Newfoundland Power to provide recovery through the 2017 GRA Cost Recovery Rider.

[36] The Isolated Systems Deferral has been allocated based upon the 2015 Test Year rural deficit allocation.

[37] 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.

[38] 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 6 represent the summation of these annual allocations.

Table 7: Estimated 2017 GRA Cost Recovery Rider – Newfoundland Power ($)

Particulars	Deferred Supply Costs (a)	2018 Excess Revenue (b)	Monthly Charge (c) = (a) + (b) / 20
Newfoundland Power	60,065,830	(21,233,259)	1,941,629

For the Island Industrial Customers, the $5,273,486 amount owing for the deferred supply cost is more than offset by the $5,315,291 in 2018 excess revenues. The remaining credit amount of $41,805 would result in a 2017 GRA Cost Recovery Rider of (0.003)¢ per kWh.[39]

4.0 2019 Customer Rate Projections

4.1 General

Hydro has assumed that final GRA customer rates will be implemented January 1, 2019; this is also the required date for updating the RSP adjustment for Island Industrial Customers. Therefore, Hydro has provided the projected January 1, 2019 rate impacts including the forecast updated RSP recovery adjustment.

Hydro has assumed a two-year amortization period to provide recovery of the 2018 revenue deficiency from the Labrador Industrial Transmission customers, the Hydro Rural Labrador Interconnected customers, and the Hydro Rural Government Diesel customers.[40]

4.2 Projected Rate Increases

Table 8 provides the projected impacts for each customer class to become effective January 1, 2019. The projected impacts include the recovery/refund of the 2018 revenue deficiency/

[39]

Annual 2019 Test Year energy	(A)	= 743,300,000 kWh
Average Monthly 2019 Test Year energy	(B) = (A)/12	= 61,941,667 kWh/month
Annual amount owing	(C)	= ($41,805)
Monthly amount owing	(D) = (C)/20	= ($2,090)
Recovery rider	(E) = (D)/(B)*100	= (0.003) cents/kWh

[40] The two-year amortization assumption was made because the rates of these customers will not increase to provide recovery of the costs of the Muskrat Falls Project and, therefore, it was assumed that new rates for these customer classes resulting from the next GRA will be implemented January 1, 2021.

excess revenue, recovery of the 2019 Test Year revenue requirement, and the recovery of the deferred supply costs over the agreed amortization period.

Table 8: Comparison of Required Increases in Customer Billings for 2019 Test Year

Customer Class	**Increase Relative to Existing Billings**		**Average Unit Cost**
	$ millions	**%**	**cents/kWh**
Newfoundland Power[41]	8.8	1.9%	7.900
Island Industrial			
Base Rate	*(2.6)*		*5.385*
RSP Update	*5.1*		*0.387*
Total Island Industrial	2.5	6.1%	5.772
Rural Labrador Interconnected	1.6	7.8%	3.287
Labrador Industrial Transmission	1.0	20.6%	$1.91/kW
Hydro Rural Government Diesel	0.5	22.7%	106.218
Hydro Rural Other[42]	0.9	1.2%	13.037

Schedule 5 to this evidence provides the supporting calculations for the estimates of customer rate impacts. The projected increase in the rates to Newfoundland Power's retail customers is 1.2% on January 1, 2019.

5.0 Revenue Requirement from Muskrat Falls

5.1 General

All components of the Muskrat Falls Project are scheduled to be fully commissioned by September 1, 2020. Government direction requires that the cost of supply from Muskrat Falls Project, including the cost of the LIL[43] and the LTA,[44] be recovered in full through Island

[41] Hydro notes that it is also forecasting a 2.3% increase to Newfoundland Power's retail customers effective July 1, 2019 as a result of the RSP credit adjustment that will conclude on June 30, 2019.
[42] 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.
[43] LIL refers to the transmission line and all related components to be constructed between the Muskrat Falls hydroelectric plant on the Churchill River and Soldier's Pond including converter stations, synchronous condensers, and terminal, telecommunications, and switchyard equipment.
[44] LTA refers to the transmission facilities of the Muskrat Falls Project to be constructed between the Muskrat Falls hydroelectric plant on the Churchill River and the generating plant located at Churchill Falls.

Interconnected rates[45] and exempts customers on the Labrador Interconnected System from paying costs related to the Muskrat Falls Project.

Nalcor's June 23, 2017 project update stated that average unit cost of electricity to supply residential customers is expected to increase to 22.89¢ per kWh (plus HST) in 2021 reflecting full cost recovery of the Muskrat Falls Project through customer rates. The present average unit cost rate to serve these customers is 12.26¢ per kWh (plus HST), which leaves a gap of 10.63¢ per kWh. Board approval of the projected 1.2% increase for 2019 for residential customers would increase residential customer rates to 12.41¢ per kWh, which leaves a gap of 10.48¢ per kWh.

Government has indicated that rate mitigation will occur to reduce the customer rate impacts. However, no defined plan has been released to inform customers on either the projected cost of electricity or the pace at which electricity rates will increase. Government has stated that it wants to be competitive with Atlantic Canadian rates, which it targets to be between 16-18¢ per kWh. Therefore, for illustrative purposes, Hydro has assumed that Government will provide rate mitigation relief for residential rates beyond 18¢ per kWh.[46]

This evidence provides additional information on the projected revenue requirement increases resulting from the Muskrat Falls Project and the projected rate increases required to provide full cost recovery at a mitigated rate of 18¢ per kWh.

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[45] OC2013-343 requires that any expenditures, payments or compensation paid directly or indirectly by Hydro under an agreement or arrangement to which the Muskrat Falls Exemption Order applies, shall be included as costs in Hydro's cost of service, without disallowance, to be recovered through Island Interconnected System customer rates.

[46] CBC News Article, April 20, 2018 *https://www.cbc.ca/news/canada/newfoundland-labrador/rates-doubling-nalcor-scrum-coady-1.4627022*
Telegram New Article, July 28, 2017 *http://www.thetelegram.com/news/local/electricity-rates-cant-go-much-above-17-cents-per-kwh-ball-says-130283/*

5.2 Muskrat Falls Project Revenue Requirements

Upon the full commissioning of the Muskrat Falls Project, supply cost payments will commence under the Transmission Funding Agreement and Muskrat Falls Power Purchase Agreement (PPA), and the role of Holyrood as a generating station will be phased-out. Historically, fuel costs from Holyrood have comprised the largest single portion of the supply costs incurred by Hydro in serving customers on the Island Interconnected system.

5.2.1 Muskrat Falls Purchase Power Agreement

The initial Muskrat Falls generation and the LTA project capital costs are collected by way of a Base Block Capital Costs Recovery payment through the Muskrat Falls PPA.[47] The Base Block Capital Costs Recovery payments for Muskrat Falls generation and the LTA reflect an internal rate of return approach to derive a price which escalates annually at a rate of 2%.[48] The required payment amounts by year are provided in Schedule 1 of the Muskrat Falls PPA and provide for the recovery of the original cost of the Muskrat Falls generation and the LTA.[49]

The Base Block Capital Cost Recovery payment amounts do not provide for the recovery of operating and maintenance costs or the investment required for sustaining capital for the assets over the 50-year supply period reflected in the contract. Muskrat Falls Corporation will estimate and bill a separate monthly charge to Hydro, with quarterly true-ups, to recover the actual operating and maintenance costs, including the cost of sustaining capital,[50] for Muskrat

[47] The LTA are the transmission facilities of the Muskrat Falls Project that are being constructed by Labrador Transmission Corporation (Labrador Transco) to interconnect the Muskrat Falls generation assets with the grid.
[48] The Base Block Capital Cost Recovery payments were computed to provide an internal rate of return of 8.4%.
[49] Schedule 1 of the Muskrat Falls PPA will be updated to reflect the costs as of the in-service date of the Muskrat Falls Project.
[50] The Muskrat Falls PPA requires Hydro to fund the sustaining capital costs for the Muskrat Falls generation and the LTA.

Falls generation and the LTA. These costs will be recovered through a charge to Hydro for operating and maintenance costs.[51]

Table 9 provides a summary of the forecast power purchase costs to meet the obligations of the Muskrat Falls PPA for the period 2020 to 2024. The forecast cost estimates are based on Nalcor Energy's Muskrat Falls Project cost estimates prepared in June 2017.

Table 9: Forecast Power Purchase Costs for Muskrat Falls Generation and LTA ($000s)

	2020	**2021**	**2022**	**2023**	**2024**
Muskrat Falls Generation	144,173	324,939	340,402	346,524	364,350
LTA	40,253	66,943	69,904	71,097	70,303
Total Muskrat Falls PPA	**184,426**	**391,882**	**410,306**	**417,621**	**434,653**

The cost estimates for 2020 provided in Table 9 reflect Muskrat Falls Project fully commissioned for a portion of the year.

5.2.2 Transmission Funding Agreement

The Transmission Funding Agreement (TFA) recovers costs associated with the LIL facilities through payments by Hydro to the LIL Opco, the operating entity. The payments to the LIL Opco are based on a cost of service approach in which the annual cost recovery amount is based on return on debt and equity plus operating and maintenance costs, depreciation and taxes.

Under the cost of service approach, cost recovery in the Transmission Funding Agreement is higher in the early years of the service period, reflecting high early levels of return due to the higher net book value of the plant. As the assets age and the net book value declines, the annual capital cost recovery declines. In accordance with the TFA, the return on equity in the

[51] Charges to Hydro for operating and maintenance costs also include other costs incurred by Muskrat Falls Corporation such as: payments to aboriginal peoples pursuant to impact and benefit agreements; payments pursuant to the water lease; payments pursuant to the Water Management Agreement; and administrative costs and taxes. The complete description of operating and maintenance costs is provided on page 15 of 76 of the Muskrat Falls PPA.

Transmission Funding Agreement will effectively reflect the approved return on equity for Newfoundland Power.[52]

In the TFA, there is also a provision for a separate charge to be estimated and billed monthly to Hydro covering the cost of sustaining capital for the LIL assets in addition to quarterly true-up adjustments to recover the difference between the actual and forecast operating and maintenance costs reflected in the charge for the annual cost recovery. These costs will be recovered through the charge from the LIL Opco to Hydro for operating and maintenance activities.[53]

Table 10 provides a summary of the forecast power purchase costs to meet the obligations of the Transmission Funding Agreement for the period 2020 to 2024.[54]

Table 10: Forecast Power Purchase Costs for the LIL ($000s)

	2020	2021	2022	2023	2024
Transmission Funding Agreement	139,146	416,689	414,107	411,532	409,180

The cost estimates for 2020 provided in Table 10 reflect Muskrat Falls Project fully commissioned for a portion of the year.

5.2.3 Reduction in Holyrood Costs

With the completion of the Muskrat Falls Project, the fuel cost incurred for generating electricity at Holyrood Thermal Generating Station will be eliminated. Relative to the forecast 2019 Test Year cost of service study, Holyrood fuel cost savings will reduce the average unit

[52] Changes in the allowed return on equity for Newfoundland Power will require a change in the annual cost recovery amount in the Transmission Funding Agreement.

[53] Unlike Muskrat Falls Corporation, the LIL Limited Partnership will internally finance sustaining capital. The LIL Opco will amortize the associated costs and bill Hydro for the capital cost recovery on a monthly basis. For the five years presented in Table 10, there are no sustaining capital costs reflected in computation of the power purchase costs shown in Table 10.

[54] The revenue requirement estimates are based on the Muskrat Falls Project cost estimates prepared in June 2017.

cost of serving Island Interconnected Customers by approximately 1.2¢ per kWh.[55] There will also be reductions in the operating and maintenance costs at Holyrood and the fixed cost resulting from the retirement of the generation assets at Holyrood. These costs comprise approximately $60 million in the 2019 Test Year cost of service study. If the full $60 million was eliminated the system average unit cost would decrease by approximately 0.9¢ per kWh.[56] However, Hydro has not yet completed its forecast costs related to Holyrood beyond 2021 as the facility is expected to be maintained to provide synchronous condenser requirements. For illustration purposes, Hydro has assumed an overall reduction in Holyrood costs of 1.8¢ per kWh for 2021.[57] Holyrood is expected to be maintained fully operational for all of 2020; therefore, Hydro expects cost savings for 2020 to reflect only reduced fuel consumption.

5.2.4 Revenue Requirement Impact of Muskrat Falls Project

From the estimated 2019 Test Year cost of service results provided in Schedule 3 to the evidence, the projected average unit cost of serving Newfoundland Power is approximately 6.8¢ per kWh (7.9¢ per kWh including the rural deficit) and 5.4¢ per kWh for the Island Industrial Customers.

Table 11 provides a high level estimate of the forecast increase in average unit costs relative to the 2019 Test Year cost of service study for the period 2020 to 2024 on the Island Interconnected System.

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[55] $82.5 million divided by approximately 7,000 GWh (i.e., 7,000, GWh is approximately the total sales to Island Interconnected system in 2019 Test Year).

[56] $60.0 million divided by approximately 7,000 GWh (i.e., 7,000, GWh is approximately the total sales to Island Interconnected system in 2019 Test Year).

[57] For illustrative purposes, the 1.8 cents/kWh chosen by Hydro reflects the projected Holyrood fuel savings (1.2 cents/kWh) and approximately 67% of the expected reductions in the operating and maintenance costs at Holyrood and the fixed cost resulting from the retirement of the generation assets at Holyrood (approximately 0.6 cents/kWh).

Table 11: Estimated Island Interconnected Revenue Requirement Impact (Muskrat Falls Project)

Year	Muskrat Falls Project Total Cost ($000s)	Forecast GWh Sales (Island Interconnected System)	Average Unit Cost in Revenue Requirement (¢/kWh)	Estimated Unit Cost of Savings from Holyrood (¢/kWh)	Net Increase in Supply costs (¢/kWh)
2020	323,572	6,964	4.7	1.2	3.5
2021	808,571	6,874	11.8	1.8	10.0
2022	824,413	6,776	12.2	1.8	10.4
2023	829,153	6,804	12.2	1.8	10.4
2024	843,833	6,842	12.3	1.8	10.5

Table 11 shows that Hydro's average unit cost of supplying customers on the Island Interconnected System is projected to increase by approximately 10¢ per kWh in 2021. Depending on the cost allocation methodology to be approved by the Board for allocation of the Muskrat Falls Project costs, the additional average unit cost between Newfoundland Power and Island Industrial Customers will differ somewhat between the two customer groups.[58] As Newfoundland Power comprises the largest portion of the load, its average unit cost increase will be close to the average increase. Therefore, the average unit cost to serve Newfoundland Power is expected to increase to approximately 18¢ per kWh.

The rates paid by the customers of Newfoundland Power must also recover the costs incurred by Newfoundland Power to provide service excluding the cost of purchases from Hydro. For the 2019 Test Year, this cost is currently estimated to be approximately 4.5¢ per kWh for residential customers.[59] Therefore, while there is uncertainty in the final overall cost to be allocated to

[58] The primary reason for the difference in average unit cost between Newfoundland Power and Island Industrial customers before rural deficit allocation is the material difference in average class load factor based on single coincident peak (i.e., lower load factor for Newfoundland Power and higher load factor of island industrial customers) which results in differences in class allocation of system demand cost (higher demand cost allocation to Newfoundland Power and lower demand cost allocation to Island Industrial Customers).

[59] This amount was estimated based on Newfoundland Power 2016 Cost of Service Study filed with its 2019 GRA evidence.

customers of Newfoundland Power post-Muskrat Falls Project commissioning, an average unit cost of between 22¢ and 23¢ per kWh appears realistic.[60]

6.0 Future Rates

6.1 General

The projected costs provided in the previous section exclude any customer cost reduction measures that will be achieved through rate mitigation, including export revenues. Government has not yet finalized its plan for rate mitigation. It is estimated that each 1¢ per kWh in rate mitigation provided to customers will require approximately $70 million per year in funding. Therefore, rate mitigation to limit residential customer rates to 18¢ per kWh will require funding in the range of $280 million to $350 million per year. This section illustrates the rate increases required to achieve a mitigated average unit cost of 18¢ per kWh for residential customer.

6.2 Managing Customer Rate Impacts

Table 12 demonstrates the required end-customer rate increases which would be required to achieve the assumed mitigated target rate of 18¢ per kWh in 2021 (Scenario 1). Table 12 assumes the starting point is the projected 2019 average unit cost of serving residential customers based on this evidence. It also assumes rate mitigation for any residential costs beyond 18¢ per kWh.

[60] This cost does not reflect any rate mitigation.

Table 12: Scenario 1 - Illustrative Rate Changes to Achieve Rate Mitigation Target

	End-Consumer Rate Increase	**Average End-Consumer Cost[61] (¢/kWh)**
2019 Test Year	1.2%	12.4
2020	28.3%	15.9
2021	13.0%	18.0

In recent years, the Board has approved rate relief measures to limit customer rate increases to 10% for any one occurrence. The continuation of this practice will require several years to enable customer rates to increase to the illustrated rate mitigation target of 18¢ per kWh.

Table 13 provides the projected residential rate if a 10% per year increase is applied to residential rates beginning January 1, 2020 (Scenario 2). Table 13 also provides an illustration of amount of deferred regulatory supply cost required for future recovery if a 10% rate increase limit is applied. Each 1¢ per kWh deficiency in recovering regulatory costs results in a $70 million revenue deficiency for each year, which is assumed to be treated as deferred regulatory supply cost. The 18¢ per kWh is assumed to be the regulatory unit cost[62] required to be recovered from customers beginning in 2021.

[61] Average end-consumer cost is equal to the previous years' cost plus the net increase in supply cost (provided in Table 11) each year to a maximum of 18 cents/kWh.

[62] Regulatory unit cost is the cost assumed to be incurred to provide service to residential customers, net of rate mitigation, for the purposes of these illustrative examples. Hydro expects to recover costs in excess of the mitigated rate from Government.

Table 13: Scenario 2 - Illustrative Rate Changes and Deferred Muskrat Falls Costs

	End-Consumer Rate Increase (a)	**Average End-Consumer Cost** (b)	**Regulatory Unit Cost** (c)	**Deferred Muskrat Falls Cost ($millions)** (d) = [(c) – (b)] x $70 million	**Cumulative Deferred Muskrat Falls Cost ($millions)** (e) = cumulative sum of (d)
2019 Test Year	1.2%	12.4	12.4	-	-
2020	10.0%	13.6	15.9	161	161
2021	10.0%	15.0	18.0	210	371
2022	10.0%	16.5	18.0	105	476
2023	9.1%	18.0	18.0	-	476

Table 13 shows that if the Board limited end-consumer rate increases to 10% per year starting in 2020, it would be 2023 before rates would increase to 18¢ per kWh. This approach would require the Board to approve a deferral account to deal with the revenue deficiencies and financing costs[63] resulting from charging customers less than 18¢ per kWh mitigated rate level.

Hydro would be required to pay the actual costs billed to it in accordance with the Muskrat Falls PPA and Transmission Funding Agreement. The funding of the rate mitigation to establish the target rate of 18¢ per kWh is assumed to be borne by Government. The funding of the financing to provide rate smoothing would need to be reflected in the deferral account balance for recovery.[64] The cumulative deferred supply costs at the time when customer rates equal the targeted rate mitigation level would need to be amortized over the longer term for future recovery from customers.

The illustration provided in Table 13 demonstrates that material increases are required to increase customer rates in spite of the level of rate mitigation that may be provided.

[63] Based on weighted average cost of capital of 5.68%, Hydro estimates financing on the balance of the deferred amounts in Table 13 would be approximately $73 million to the end of 2023.
[64] No financing costs are assumed for the illustration provided in Table 13.

6.3 2019 Rate Smoothing Option

As indicated in the evidence, the projected rate increase for residential customers in 2019 is 1.2%. Hydro estimates that an additional 2.3% increase is expected in July 2019 as a result of the operation of the RSP;[65] however, the RSP impact is not reflected in Tables 12-14. There is an opportunity to initiate the rate smoothing process in 2019 by applying a rate stability rider in addition to the 2017 GRA increase.

The rate stability rider could be established to permit a slightly larger increase in rates in addition to the increase in rates presented in Scenario 2 (i.e., 1.2%) or to make additional progress towards the target rate for rate mitigation. Funds collected through the rate stability rider could be held in a deferral account and applied to reduce the amount for future recovery of the deferred Muskrat Falls supply costs.

Table 14 provides the projected residential rates reflecting the 2019 GRA rates (1.2%) with an additional 6.5%[66] applied as a rate stability rider (Scenario 3).

Table 14: Scenario 3 - Illustrative Rate Changes and Deferred Muskrat Falls Costs

	End-Consumer Rate Increase (Decrease) (a)	**Average End-Consumer Cost** (b)	**Regulatory Unit Cost** (c)	**Deferred Muskrat Falls Cost ($millions)** (d) = [(c) – (b)] x $70 million	**Cumulative Deferred Muskrat Falls Cost ($millions)** (e) = cumulative sum of (d)
2019 Test Year	7.7%	13.2	12.4	(56)	(56)
2020	10.0%	14.5	15.9	98	42
2021	10.0%	16.0	18.0	140	182
2022	10.0%	17.6	18.0	28	210
2023	2.0%	18.0	18.0	-	210

[65] On July 1, 2019, Newfoundland Power's current plan credit of (0.296) cents per kWh will expire.

[66] 6.5% is shown as the 2019 rate stability rider for illustrative purposes as it, combined with the base rate increase of 1.2% and the July 1, 2019 RSP increase of 2.3%, will add to a total end-customer rate increase of 10% in 2019.

The implementation of a 6.5% rate stability rider in 2019 reduces the deferred supply costs by approximately $266 million to $210 million[67] (excluding financing costs) relative to Scenario 2 as a result of achieving the transition to 18¢ per kWh earlier.

The illustrative examples provided in this evidence demonstrate the importance of starting the rate smoothing process in 2019 with a view to limiting the cost to be deferred for recovery from future customers.

6.4 Expected Supply Scenario Forecast Risk

There remains material uncertainty in the savings from Hydro's fuel/supply costs that are included in the 2018 and 2019 Test Years reflecting the Expected supply Scenario. The savings from off-island purchases reflected in the 2018 Test Year is $44.2 million and the savings reflected in the 2019 test Year is $85.7 million. This approximate $130 million in savings is contributing to a material reduction in revenue requirement to be recovered through customer rates in 2019. The forecast total savings from off-island purchases reflected in proposed customer rates depends on: (i) the availability of the LIL during the testing period; (ii) the amount of Recapture Energy available from Labrador; (iii) the cost of No. 6 fuel; and (iv) the availability and pricing of purchases from other jurisdictions.

If the forecast savings in off-island purchases are overstated, the customer rates that will be implemented in 2019 will not recover Hydro's cost of supplying customers on the Island Interconnected System. These cost variances resulting from reduced savings in off-island purchases would be recorded in the Revised Energy Supply Cost Variance Deferral Account for future recovery from customers. The requirement for future recovery of deferred 2018 and 2019 supply costs beyond the additional costs for the Muskrat Falls Project would increase the challenge of recovering the future cost of supplying customers.

[67] Based on weighted average cost of capital of 5.68%, Hydro estimates financing on the balance of the deferred amounts in Table 14 would be approximately $30 million to the end of 2023.

The implementation of a rate stability rider in 2019 would limit the exposure to customers of bearing these costs in future.

7.0 Conclusion

This evidence provides estimated revenue requirements and projected rates reflecting the two settlement agreements concluded during the 2017 GRA process. Hydro has also adjusted its cost of service studies and rate change projections for customers on the Labrador Interconnected System reflecting the delayed approval of the transmission capital project for Labrador East.

The revised rate projections provide for materially lower rates in 2019 for customers than those which were originally proposed in Hydro's application. The reduced revenue requirements reflect the provision of savings from off-island purchases (resulting from the use of LIL and LTA) in the determination of rates for 2019.

Based on the 2019 projected customer rates for residential customers on the Island Interconnected System (an average unit cost 12.4¢ per kWh plus HST), there is more than 10¢ per kWh deficiency compared to the estimated cost to serve residential customers in 2021. Hydro has assumed that Government will fund the costs required for rate mitigation to limit rate increases to 18¢ per kWh plus HST in 2021. If the Board applies a customer rate impact limit of 10% per year (consistent with past practice), a material amount of costs incurred by Hydro as a result of increase power purchases related to the Muskrat Falls Project will need to be deferred for future recovery from customers.

The forecast savings from off-island purchases reflected in proposed rates is approximately $130 million. This forecast reflects a number of assumptions that are beyond Hydro's control. If some of these assumptions do not materialize, additional Holyrood fuel costs will be incurred and create a large fuel cost balance owing to be recovered from future customers. In this circumstance, customers in 2019 would pay rates that would be below cost and future customers would be required to pay rates that include both the cost of deferred Holyrood fuel costs and the costs of the Muskrat Falls Project.

Given the projected rate increase for residential customers to become effective in January 1, 2019 is 1.2%, Hydro believes the Board should consider implementation of a rate stability rider at the time of implementing 2017 GRA final rates. The rate stability rider would permit a higher rate increase to be implemented in 2019 and limit the rate impact on future customers if the savings from off-island purchases are lower than forecast. Even if the actual savings from off-island purchases meet or exceed the savings reflected in the 2018 and 2019 test years, the rate stability rider would still be beneficial to customers in that it would reduce the amount of Muskrat Falls Project costs to be deferred for recovery through future rates.

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

Month	2015 Test Year No. 6 Fuel[1] (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) = (a) + (b)	(d)	(e) = [(c) x (d)] /1000
January	415,518	(502)	415,016	$57.55	23,884
February	375,307	(32,379)	342,929	$59.85	20,524
March	395,728	(3,317)	392,411	$61.41	24,098
April	255,307	(2,816)	252,492	$61.41	15,506
May	197,864	-	197,864	$62.64	12,394
June	76,586	(21,845)	54,741	$62.64	3,429
July	-	(58,689)	(58,689)	$62.64	(3,676)
August	-	(78,252)	(78,252)	$62.64	(4,902)
September	25,534	(116,052)	(90,518)	$62.64	(5,670)
October	164,887	(197,411)	(32,524)	$66.51	(2,163)
November	255,307	(227,395)	27,913	$71.70	2,001
December	415,618	(241,602)	174,016	$76.05	13,234
Total	**2,577,657**	**(980,259)**	**1,597,398**		**98,659**

[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)	605,800,000
2015 Test Year Conversion Rate (BBLs/kWh)	618
Reduced Barrels (BBLs)	(980,259)

[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	23,884	29
February	22,462	20,524	1,938
March	24,302	24,098	204
April	15,678	15,506	173
May	12,394	12,394	-
June	4,797	3,429	1,368
July	-	(3,676)	3,676
August	-	(4,902)	4,902
September	1,599	(5,670)	7,269
October	10,967	(2,163)	13,130
November	18,306	2,001	16,304
December	31,608	13,234	18,374
Total	**166,026**	**98,659**	**67,367**

NEWFOUNDLAND AND LABRADOR HYDRO
2018 Test Year Cost of Service Study Reflecting Expected Supply and Settlement Agreement
Total System
Comparison of Existing 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	364,521,848	-	55,767,235	420,289,083	
2	Subtotal Newfoundland Power	**441,522,342**	**364,521,848**	**-**	**55,767,235**	**420,289,083**	**1.21**
3	Island Industrial	41,537,493	36,222,202	-	-	36,222,202	1.15
4	Labrador Industrial	4,739,196	4,919,495	-	-	4,919,495	0.96
5	CFB - Goose Bay Secondary	-	-	-	-	-	-
6	Rural Labrador Interconnected	20,166,629	17,873,115	-	2,734,361	20,607,476	1.13
	Rural Deficit Areas						
7	Island Interconnected	49,923,516	67,290,028	-	(17,366,512)	49,923,516	0.74
8	Island Isolated	1,552,252	10,699,090	-	(9,146,838)	1,552,252	0.15
9	Labrador Isolated	8,660,229	37,011,402	-	(28,351,172)	8,660,229	0.23
10	L'Anse au Loup	2,966,014	6,603,088	-	(3,637,074)	2,966,014	0.45
11	CFB Revenue Credit Applied to Deficit	-	-	-	-	-	-
12	**Subtotal**	**63,102,011**	**121,603,607**	**-**	**(58,501,596)**	**63,102,011**	**0.52**
13	**Total**	**571,067,671**	**545,140,266**	**-**	**-**	**545,140,266**	**1.05**

Reference: 2018 Test Year Cost of Service Schedule 1.2

NEWFOUNDLAND AND LABRADOR HYDRO
2018 Test Year Cost of Service Study Reflecting Expected Supply and Settlement Agreement
Island Interconnected
Comparison of Existing 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.2/3)
	Island Interconnected						
1	Newfoundland Power	441,522,342	364,521,848	-	55,767,235	420,289,083	
2	**Subtotal Newfoundland Power**	**441,522,342**	**364,521,848**	**-**	**55,767,235**	**420,289,083**	**1.21**
3	Industrial - Firm	41,537,493	36,222,202	-		36,222,202	
4	Industrial - Non-Firm	-	-	-		-	
5	**Subtotal Industrial**	**41,537,493**	**36,222,202**	**-**	**-**	**36,222,202**	**1.15**
	Rural						
6	1.1 Domestic	13,521,092	21,363,590	-	(7,842,499)	13,521,092	0.63
7	1.12 Domestic All Electric	17,033,160	23,998,923	-	(6,965,763)	17,033,160	0.71
8	1.3 Special	19,223	66,034	-	(46,810)	19,223	0.29
9	2.1 General Service 0-100 kW	9,123,294	11,085,472	-	(1,962,178)	9,123,294	0.82
10	2.3 General Service 110-1,000 kVa	5,943,467	6,287,963	-	(344,495)	5,943,467	0.95
11	2.4 General Service Over 1,000 kVa	3,289,595	3,285,506	-	4,088	3,289,595	1.00
12	4.1 Street and Area Lighting	993,685	1,202,540	-	(208,855)	993,685	0.83
13	**Subtotal Rural**	**49,923,516**	**67,290,028**	**-**	**(17,366,512)**	**49,923,516**	**0.74**
14	**Total Island Interconnected**	**532,983,351**	**468,034,077**	**-**	**38,400,723**	**506,434,801**	**1.14**

Reference: 2018 Test Year Cost of Service Schedule 1.2

NEWFOUNDLAND AND LABRADOR HYDRO
2018 Test Year Cost of Service Study Reflecting Expected Supply and Settlement Agreement
Island Isolated
Comparison of Existing 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	780,035	8,218,364		(7,438,329)	780,035	0.09
2	1.2G Government Domestic Diesel	-	-		-	-	-
2	1.23 Churches, Schools & Com Halls	63,100	317,124		(254,025)	63,100	0.20
3	2.1 General Service 0-10 kW	206,177	859,132		(652,955)	206,177	0.24
4	2.2 GS 10-100 kW	459,017	1,101,406		(642,390)	459,017	0.42
5	4.1 Street and Area Lighting	38,040	193,728		(155,688)	38,040	0.20
6	4.1G Gov't Street and Area Lighting	5,882	9,335		(3,453)	5,882	0.63
7	**Total**	**1,552,252**	**10,699,090**		**(9,146,838)**	**1,552,252**	**0.15**

Reference: 2018 Test Year Cost of Service Schedule 1.2

NEWFOUNDLAND AND LABRADOR HYDRO
2018 Test Year Cost of Service Study Reflecting Expected Supply and Settlement Agreement
Labrador Isolated
Comparison of Existing Revenue & Allocated Revenue Requirement

Line No.	1 Rate Class	2 Revenues ($)	3 Cost of Service Before Deficit and Revenue Credit Allocation ($)	4 Revenue Credit ($)	5 Deficit ($)	6 Revenue Requirement After Deficit and Revenue Credit Allocation (Col.3+4+5) ($)	7 Revenue to Cost Coverage (Col.2/3)
	Labrador Isolated						
1	1.2 Domestic Diesel	3,030,680	19,896,622		(16,865,942)	3,030,680	0.15
2	1.2G Government Domestic Diesel	517,117	534,968		(17,851)	517,117	0.97
3	1.23 Churches, Schools & Com Halls	277,232	1,082,305		(805,073)	277,232	0.26
4	2.1 General Service 0-10 kW	1,240,331	3,671,600		(2,431,270)	1,240,331	0.34
5	2.2 GS 10-100 kW	3,007,950	8,547,716		(5,539,767)	3,007,950	0.35
6	2.3 GS 110-1,000 kVa	243,729	1,351,627		(1,107,898)	243,729	0.18
7	2.4 General Service Over 1,000 kVa	224,074	1,559,715		(1,335,641)	224,074	0.14
8	2.5 GS Diesel	-	-		-	-	-
9	2.5G Gov't General Service Diesel	-	-		-	-	-
8	4.1 Street and Area Lighting	110,871	358,158		(247,287)	110,871	0.31
9	4.1G Gov't Street and Area Lighting	8,246	8,691		(445)	8,246	0.95
10	**Total**	**8,660,229**	**37,011,402**		**(28,351,172)**	**8,660,229**	**0.23**

Reference: 2018 Test Year Cost of Service Schedule 1.2

NEWFOUNDLAND AND LABRADOR HYDRO
2018 Test Year Cost of Service Study Reflecting Expected Supply and Settlement Agreement
L'Anse au Loup
Comparison of Existing 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	551,356	1,410,108		(858,752)	551,356	0.39
2	1.12 Domestic All Electric	1,294,971	3,070,391		(1,775,420)	1,294,971	0.42
3	2.1 General Service 0-100 kW	789,363	1,541,712		(752,348)	789,363	0.51
3	2.3 General Service 110-1,000 kVa	311,399	537,016		(225,618)	311,399	0.58
4	4.1 Street and Area Lighting	18,925	43,860		(24,935)	18,925	0.43
5	**Total L'Anse Au Loup**	**2,966,014**	**6,603,088**		**(3,637,074)**	**2,966,014**	**0.45**

Reference: 2018 Test Year Cost of Service Schedule 1.2

NEWFOUNDLAND AND LABRADOR HYDRO
2018 Test Year Cost of Service Study Reflecting Expected Supply and Settlement Agreement
Labrador Interconnected
Comparison of Existing 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	4,919,495		-	4,919,495	0.96
2	Labrador Industrial Non-Firm	-	-		-	-	-
3	**Subtotal Industrial**	**4,739,196**	**4,919,495**	**-**	**-**	**4,919,495**	
4	CFB - Goose Bay Secondary	-	-	-	-	-	-
	Rural						
5	1.1 Domestic	99,239	204,588	-	31,299.34	235,887	0.42
6	1.1A Domestic All Electric	11,006,553	10,945,154	-	1,674,470	12,619,625	0.87
7	2.1 General Service 0-10 kW	404,754	365,897	-	55,978	421,875	0.96
8	2.2 General Service 10-100 kW	2,234,077	1,671,088	-	255,655	1,926,743	1.16
9	2.3 General Service 110-1,000 kVa	3,452,666	2,285,439	-	349,643	2,635,082	1.31
10	2.4 General Service Over 1,000 kVa	2,608,075	2,107,458	-	322,414	2,429,872	1.07
11	4.1 Street and Area Lighting	361,265	293,491	-	44,900	338,392	1.07
12	**Subtotal Rural**	**20,166,629**	**17,873,115**	**-**	**2,734,361**	**20,607,476**	
13	**Total Labrador Interconnected**	**24,905,825**	**22,792,610**	**-**	**2,734,361**	**25,526,970**	

Reference: 2018 Test Year Cost of Service Schedule 1.2

NEWFOUNDLAND AND LABRADOR HYDRO
2019 Test Year Cost of Service Study Reflecting Expected Supply and Settlement Agreement
Total System
Comparison of Forecast 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	460,932,442	398,161,574	-	62,778,520	460,940,094	
2	Subtotal Newfoundland Power	**460,932,442**	**398,161,574**	**-**	**62,778,520**	**460,940,094**	**1.16**
3	Island Industrial	40,060,391	40,053,848	-	-	40,053,848	1.00
4	Labrador Industrial	5,623,221	5,619,822	-	-	5,619,822	1.00
5	CFB - Goose Bay Secondary	-	-	-	-	-	-
6	Rural Labrador Interconnected	21,310,952	18,426,362	-	2,905,302	21,331,665	1.16
	Rural Deficit Areas						
7	Island Interconnected	51,758,381	70,117,145	-	(18,358,764)	51,758,381	0.74
8	Island Isolated	1,675,600	11,701,325	-	(10,025,725)	1,675,600	0.14
9	Labrador Isolated	9,314,682	42,187,559	-	(32,872,877)	9,314,682	0.22
10	L'Anse au Loup	3,137,443	7,563,899	-	(4,426,456)	3,137,443	0.41
11	CFB Revenue Credit Applied to Deficit	-	-	-	-	-	-
12	**Subtotal**	**65,886,105**	**131,569,928**	**-**	**(65,683,822)**	**65,886,105**	**0.50**
13	**Total**	**593,813,111**	**593,831,533**	**-**	**-**	**593,831,533**	**1.00**

Reference: 2019 Test Year Cost of Service Schedule 1.2

NEWFOUNDLAND AND LABRADOR HYDRO
2019 Test Year Cost of Service Study Reflecting Expected Supply and Settlement Agreement
Island Interconnected
Comparison of Forecast Revenue & Allocated Revenue Requirement

Line No.	1 Rate Class	2 Revenues ($)	3 Cost of Service Before Deficit and Revenue Credit Allocation ($)	4 Revenue Credit ($)	5 Deficit Allocation ($)	6 Revenue Requirement After Deficit and Revenue Credit Allocation (Col.3+4+5) ($)	7 Revenue to Cost Coverage (Col.2/3)
	Island Interconnected						
1	Newfoundland Power	460,932,442	398,161,574	-	62,778,520	460,940,094	
2	**Subtotal Newfoundland Power**	**460,932,442**	**398,161,574**	**-**	**62,778,520**	**460,940,094**	**1.16**
3	Industrial - Firm	40,060,391	40,053,848	-		40,053,848	
4	Industrial - Non-Firm	-	-	-		-	
5	**Subtotal Industrial**	**40,060,391**	**40,053,848**	**-**	**-**	**40,053,848**	**1.00**
	Rural						
6	1.1 Domestic	14,171,422	22,336,734	-	(8,165,311)	14,171,422	0.63
7	1.12 Domestic All Electric	17,942,081	25,179,419	-	(7,237,337)	17,942,081	0.71
8	1.3 Special	19,501	69,617	-	(50,117)	19,501	0.28
9	2.1 General Service 0-100 kW	9,300,612	11,433,995	-	(2,133,383)	9,300,612	0.81
10	2.3 General Service 110-1,000 kVa	6,003,893	6,482,306	-	(478,413)	6,003,893	0.93
11	2.4 General Service Over 1,000 kVa	3,312,858	3,392,187	-	(79,329)	3,312,858	0.98
12	4.1 Street and Area Lighting	1,008,014	1,222,888	-	(214,874)	1,008,014	0.82
13	**Subtotal Rural**	**51,758,381**	**70,117,145**	**-**	**(18,358,764)**	**51,758,381**	**0.74**
14	**Total Island Interconnected**	**552,751,214**	**508,332,566**	**-**	**44,419,756**	**552,752,322**	**1.09**

Reference: 2019 Test Year Cost of Service Schedule 1.2

NEWFOUNDLAND AND LABRADOR HYDRO
2019 Test Year Cost of Service Study Reflecting Expected Supply and Settlement Agreement
Island Isolated
Comparison of Forecast 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	815,374	8,965,468		(8,150,094)	815,374	0.09
2	1.2G Government Domestic Diesel	-	-		-	-	-
2	1.23 Churches, Schools & Com Halls	66,209	351,233		(285,024)	66,209	0.19
3	2.1 General Service 0-10 kW	224,331	952,277		(727,946)	224,331	0.24
4	2.2 GS 10-100 kW	524,773	1,209,076		(684,302)	524,773	0.43
5	4.1 Street and Area Lighting	38,589	213,336		(174,748)	38,589	0.18
6	4.1G Gov't Street and Area Lighting	6,323	9,935		(3,612)	6,323	0.64
7	**Total**	**1,675,600**	**11,701,325**		**(10,025,725)**	**1,675,600**	**0.14**

Reference: 2019 Test Year Cost of Service Schedule 1.2

NEWFOUNDLAND AND LABRADOR HYDRO
2019 Test Year Cost of Service Study Reflecting Expected Supply and Settlement Agreement
Labrador Isolated
Comparison of Forecast 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	3,204,211	22,634,337		(19,430,126)	3,204,211	0.14
2	1.2G Government Domestic Diesel	632,270	604,603		27,667	632,270	1.05
3	1.23 Churches, Schools & Com Halls	291,235	1,245,882		(954,647)	291,235	0.23
4	2.1 General Service 0-10 kW	1,350,557	4,193,909		(2,843,352)	1,350,557	0.32
5	2.2 GS 10-100 kW	3,232,573	9,751,149		(6,518,575)	3,232,573	0.33
6	2.3 GS 110-1,000 kVa	252,028	1,557,953		(1,305,925)	252,028	0.16
7	2.4 General Service Over 1,000 kVa	230,475	1,794,556		(1,564,081)	230,475	0.13
8	2.5 GS Diesel	-	-		-	-	-
9	2.5G Gov't General Service Diesel	-	-		-	-	-
8	4.1 Street and Area Lighting	112,470	395,649		(283,179)	112,470	0.28
9	4.1G Gov't Street and Area Lighting	8,864	9,522		(658)	8,864	0.93
10	**Total**	**9,314,682**	**42,187,559**		**(32,872,877)**	**9,314,682**	**0.22**

Reference: 2019 Test Year Cost of Service Schedule 1.2

NEWFOUNDLAND AND LABRADOR HYDRO
2019 Test Year Cost of Service Study Reflecting Expected Supply and Settlement Agreement
L'Anse au Loup
Comparison of Forecast 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	575,793	1,560,796		(985,003)	575,793	0.37
2	1.12 Domestic All Electric	1,388,811	3,528,557		(2,139,746)	1,388,811	0.39
3	2.1 General Service 0-100 kW	832,440	1,788,203		(955,763)	832,440	0.47
3	2.3 General Service 110-1,000 kVa	321,202	640,202		(319,000)	321,202	0.50
4	4.1 Street and Area Lighting	19,198	46,140		(26,943)	19,198	0.42
5	**Total L'Anse Au Loup**	**3,137,443**	**7,563,899**		**(4,426,456)**	**3,137,443**	**0.41**

Reference: 2019 Test Year Cost of Service Schedule 1.2

NEWFOUNDLAND AND LABRADOR HYDRO
2019 Test Year Cost of Service Study Reflecting Expected Supply and Settlement Agreement
Labrador Interconnected
Comparison of Forecast 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	5,623,221	5,619,822		-	5,619,822	1.00
2	Labrador Industrial Non-Firm	-	-		-	-	-
3	**Subtotal Industrial**	**5,623,221**	**5,619,822**	**-**	**-**	**5,619,822**	
4	CFB - Goose Bay Secondary	-	-	-	-	-	-
	Rural						
5	1.1 Domestic	103,541	205,376	-	32,381.79	237,758	0.44
6	1.1A Domestic All Electric	11,671,975	11,295,425	-	1,780,961	13,076,385	0.89
7	2.1 General Service 0-10 kW	430,543	376,614	-	59,381	435,995	0.99
8	2.2 General Service 10-100 kW	2,372,655	1,748,756	-	275,728	2,024,484	1.17
9	2.3 General Service 110-1,000 kVa	3,680,484	2,404,347	-	379,096	2,783,442	1.32
10	2.4 General Service Over 1,000 kVa	2,690,490	2,103,084	-	331,595	2,434,679	1.11
11	4.1 Street and Area Lighting	361,265	292,762	-	46,160	338,922	1.07
12	**Subtotal Rural**	**21,310,952**	**18,426,362**	**-**	**2,905,302**	**21,331,665**	
13	**Total Labrador Interconnected**	**26,934,172**	**24,046,184**	**-**	**2,905,302**	**26,951,487**	

Reference: 2019 Test Year Cost of Service Schedule 1.2

Computation of 2018 Revenue Excess/(Deficiency)

Revenue Excess/(Deficiency) Before Allocation of 2018 Rural Deficit ($000s)

Particulars	**Forecast 2018 Revenues**	**2018TY Costs Excluding Rural Deficit**	**Revenue Excess/(Deficiency)**	**Revenue to Cost Ratio**
Newfoundland Power	441,522	364,522	77,000	1.21
Island Industrial Customers	41,537	36,222	5,315	1.15
Labrador Interconnected	20,167	17,873	2,294	1.13
Other Hydro Rural	63,102	121,604	(58,502)	0.52
Labrador Industrial Transmission	4,739	4,919	(180)	0.96
Total	**571,068**	**545,140**	**25,927**	**1.05**

Allocation of 2018 Rural Deficit ($000s)

Particulars	**2018TY Costs Excluding Rural Deficit**	**Rural Deficit Allocation**	**2018TY Revenue Requirement**	**Revenue to Cost Ratio**
Newfoundland Power	364,522	55,767	420,289	1.15
Labrador Interconnected	17,873	2,734	20,607	1.15
Total	**382,395**	**58,502**	**440,897**	

2018 Revenue Excess/(Deficiency) by Customer Class ($000s)

Particulars	**Forecast 2018 Revenues**	**2018 TY Costs Including Revenue Deficiency**	**Revenue Excess/(Deficiency)**	**Revenue to Cost Ratio**
Newfoundland Power	441,522	420,289	21,233	1.05
Island Industrial Customers	41,537	36,222	5,315	1.15
Labrador Interconnected Rural	20,167	20,607	(441)	0.98
Labrador Industrial Transmission	4,739	4,919	(180)	0.96
Rural Government Diesel	2,076	2,265	(189)	0.92

Computation of 2019 Revenue Excess/(Deficiency)

Revenue Excess/(Deficiency) Before Allocation of 2019 Rural Deficit ($000s)

Particulars	**Forecast 2019 Revenues**	**2019TY Costs Excluding Rural Deficit**	**Revenue Excess/(Deficiency)**	**Revenue to Cost Ratio**
Newfoundland Power	450,781	398,162	52,619	1.13
Island Industrial Customers	42,678	40,054	2,625	1.07
Labrador Interconnected	20,175	18,426	1,748	1.09
Other Hydro Rural	64,627	131,570	(66,943)	0.49
Labrador Industrial Transmission	4,733	5,620	(886)	0.84
Total	**582,994**	**593,832**	**(10,838)**	**0.98**

Allocation of 2019 Rural Deficit ($000s)

Particulars	**2018TY Costs Excluding Rural Deficit**	**Rural Deficit Allocation**	**2018TY Revenue Requirement**	**Revenue to Cost Ratio**
Newfoundland Power	398,162	62,779	460,940	1.16
Labrador Interconnected	18,426	2,905	21,332	1.16
Total	**416,588**	**65,684**	**482,272**	

2019 Revenue Excess/(Deficiency) by Customer Class ($000s)

Particulars	**Forecast 2019 Revenues**	**2018 TY Costs Including Revenue Deficiency**	**Revenue Excess/(Deficiency)**	**Revenue to Cost Ratio**
Newfoundland Power	450,781	460,940	(10,160)	0.98
Island Industrial Customers	42,678	40,054	2,625	1.07
Labrador Interconnected Rural	20,175	21,332	(1,157)	0.95
Labrador Industrial Transmission	4,733	5,620	(886)	0.84
Rural Government Diesel	2,075	2,433	(357)	0.85

Newfoundland and Labrador Hydro
2019 Required Increase in Customer Billings – Expected Supply Scenario
Island Industrial Customers

	2019 Test Year Billing Units	Unit	2018 Interim Rates[1]	2019 Billings at Existing Rates ($)	Particulars		Forecast 2019 Billings ($)	Change ($)	Change (%)
Demand (kWs)	1,158,000	$/kW/mo	9.95	11,522,100	2019TY Revenue Requirement		40,053,848		
Energy - Firm (MWhs)	743,300	¢/kWh	3.971	29,516,443	2018 Revenue Excess[2]		(3,189,175)		
Spec. Assigned		$	1,639,833	1,639,833	Supply Costs Recovery[3]		3,164,092		
Total Base Rate				**42,678,376**			**40,028,765**		
RSP: Current Plan	743,300	¢/kWh	(0.285)	(2,118,405)		0.377	2,802,241		
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				**40,455,909**			**42,905,336**	**2,449,427**	**6.1%**

[1] Based on rates proposed to be effective July 1, 2018.
[2] 2018 Revenue Excess amortized over 20 months.
[3] Island Industrial Customer's portion of the $65.4M in deferred supply costs amortized over 20 months.

Newfoundland and Labrador Hydro
2019 Required Increase in Customer Billings – Expected Supply Scenario
Newfoundland Power

	2019 Billing Units at 2018 First Block Size	Unit	2018 Interim Rate [1]	Existing Billings ($)	2018 Interim Rate	2019TY Revenue Requirement	2018 Revenue Excess[2]	Recovery of Deferred Supply Costs	Forecast 2019 Billings ($)	Change ($)	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**		**460,940,094**	**(12,739,955)**	**36,039,498**	**484,239,636**	**33,459,102**	
RSP Recovery Adjustment-Normal	5,833,600	¢/kWh	(0.296)	(17,267,456)	0.000	(17,267,456)					
RSP Fuel Rider	5,833,600	¢/kWh	0.423	24,676,128	0.000	-					
CDM Recovery Adjustment	5,833,600	¢/kWh	0.022	1,283,392	0.022	1,283,392					
Total				**459,472,598**		**444,956,030**	**(12,739,955)**	**36,039,498**	**468,255,572**	**8,782,974**	1.9%
										End-Consumer Impact[4]	**1.2%**

[1] Based on rates proposed to be effective July 1, 2018.
[2] 2018 Revenue Excess 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
Remaining Classes

	2019 Test Year Billing Units	Unit	Existing Average Unit Cost[1]	Existing Billings ($)	Projected Average Unit Cost[2]	Revenue Requirement 2019 Cost of Service	2018 Revenue Deficiency (12/20)[5]	Balance owing to customers in accordance with Board Order P.U. 22(2017)	Change ($)	Change (%)
Rural Labrador Interconnected	655,748,310	$/kWh	0.030	19,989,234	0.033	21,331,665	220,423	(211,332)	1,351,523	**6.8%**
Hydro Rural Government	2,396,960	$/kWh	0.866	2,075,306	1.062	2,432,531	113,478		470,702	**22.7%**
Hydro Rural Other[4]	486,719,690	$/kWh	0.129	62,551,580	0.130	63,453,574	-		901,994	**1.2%**
Labrador Industrial[3]	2,940,000	$/kW	1.61	4,733,400	1.91	5,619,822	90,149		976,571	**20.6%**

[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 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 forecast to occur over 24 months.