# Board of Commissioners of Public Utilities
# Financial Consultants Report
# Newfoundland Power Inc.
# 2019-2020 General Rate Application Hearing

September 25, 2018

# Contents

## Restrictions, Qualifications and Independence

This report is not intended for general circulation or publication nor is it to be reproduced or used for any purpose other than that outlined herein without our prior written permission in each specific instance. Notwithstanding the above, we understand that our report may be disclosed as a part of a public hearing process. We have given the Board our consent to use our report for this purpose.

Our scope of work is as set out in our terms of reference letter, which is referenced throughout this report. The procedures undertaken in the course of our review do not constitute an audit of Newfoundland Power Inc.'s ("the Company") ("Newfoundland Power") financial information and consequently, we do not express an opinion on the financial information provided by Newfoundland Power. In preparing this report, we have relied upon information provided by Newfoundland Power.

We acknowledge that the Board is bound by the Freedom of Information and Protection of Privacy Act and agree that the Board may use its sole discretion in any determination of whether and, if so, in what form, this Report may be required to be released under this Act.

We reserve the right, but will be under no obligation, to review and/or revise the contents of this report in light of information which becomes known to us after the date of our report.

# Introduction and Scope

This report to the Board of Commissioners of Public Utilities ("the Board") presents our observations, findings and recommendations with respect to our financial analysis of the pre-filed evidence of the Company, which was submitted to the Board on June 1, 2018 in support of its 2019/2020 General Rate Application ("GRA" or "Application").

*Scope and Limitations*

The detailed scope of our financial review of the Company's pre-filed evidence is as follows:

**Review of the following as detailed in Newfoundland Power Inc.'s 2019/2020 General Rate Application:**

- Review of the changes to the accounting practices regarding capitalization of pension expenses.
- Review the proposal to amortize the forecast 2019 revenue surplus over a 34 month period.
- Review the proposal to recover Board and Consumer Advocate costs associated with the Application over a 34 month period.

**Review of 2019 and 2020 financial forecast including the following:**

- Examine the Company's chart of accounts to determine whether it complies with the System of Accounts prescribed by the Board.
- Examine the methodology and assumptions used by the Company for estimating revenues, expenses and net earnings and determine whether they are reasonable and appropriate.
- Conduct a review of actual and forecast capital expenditures, revenues, expenses, net earnings, and return on rate base and return on common equity for the years ended December 31, 2015, December 31, 2016 and December 31, 2017 (actual), and for the years ending December 31, 2018, December 31, 2019 and December 31, 2020 (forecast).
- Verify the Company's calculation of the proposed rate of return on rate base, cost of capital and return on common equity for the years ending December 31, 2019 and December 31, 2020.
- Verify the calculation of proposed rates necessary to meet the estimated revenue requirements in the 2019 and 2020 test years.
- Review the Company's calculation of estimated average rate base for the years ending December 31, 2019 and December 31, 2020.

The nature and extent of the procedures which we performed in our analysis varied for each of the items in the Terms of Reference. In general, our procedures were comprised of:

- enquiry and analytical procedures with respect to financial information in the Company's records;
- assessing the reasonableness of the Company's explanations; and,
- assessing the Company's compliance with Board Orders.

**The financial statements of the Company for the years ended December 31, 2015 and December 31, 2016 have been audited by Ernst & Young LLP, Chartered Professional Accountants. The financial statements of the Company for the year ended December 31, 2017 have been audited by Deloitte LLP, Chartered Professional Accountants. The auditors have expressed their unqualified opinion on the fairness of the statements in their reports for each year. In the course of completing our procedures we have, in certain circumstances, referred to the audited financial statements and the historical financial information contained therein.**

## Capitalization of Pension Expenses

Newfoundland Power has noted that Accounting Standards Update 2017-07 – Improving the Presentation of Net Periodic Pension Cost and Net Periodic Post-retirement Benefit Cost (the "Update") which was issued in March of 2017 and effective on January 1, 2018, will have an impact on how the Company accounts for pension costs in accordance with US Generally Accepted Accounting Principles (GAAP). As a result, the Company has changed their methodology in 2018 to reflect only the current service cost component of pension expense in the amount capitalized, consistent with the Update. The Company is further proposing to revise the capitalization rate for pension expense from 11% to 46% based on overall Company labour allocation for 2019 and 2020. This would be consistent with the current treatment for the capitalization of OPEB costs and industry practice. The effect of the new methodology is a decrease in revenue requirement for 2019 and 2020. We recalculated the revised pension capitalization based on the new methodology and found no discrepancies.

**We have reviewed the applicable US GAAP Update and agree with the Company's conclusions as it relates to the changes in its accounting practices regarding capitalization of pension expense.**

# Regulatory Deferral Accounts

Newfoundland Power has certain regulatory amortizations which impact the revenue requirement. The amortization of regulatory deferrals is summarized in the table below:

**Table 1: Amortization of Regulatory Deferrals 2016-2020P**

| ($000s) | 2016 | 2017 | 2018F | 2019P | 2020P |
|---|---|---|---|---|---|
| 2016/2017 Hearing Costs Deferral | $ 171 | $ 341 | $ 341 | $ - | $ - |
| 2016 Revenue Surplus | 2,064 | (1,032) | (1,032) | - | - |
| 2019/2020 Hearing Costs Deferral | - | - | - | 294 | 353 |
| 2019 Revenue Surplus | - | - | - | 649 | (324) |
| **Revenue Requirement Impact** | **$ 2,235** | **$ (691)** | **$ (691)** | **$ 943** | **$ 29** |

## Previously Approved Regulatory Deferrals

The 2018 forecast amortization of regulatory deferrals consists of accounts that were previously approved by the Board as follows:

- **2016/2017 General Rate Application Costs:** With respect to the costs relating to the 2016/2017 GRA, the Company proposed that these costs be recovered in customer rates from July 1, 2016 to December 31, 2018 up to $1,200,000, and any costs over this amount be collected through the Rate Stabilization Account ("RSA"). This was approved in Board Order No. P.U. 18 (2016), except estimated costs were reduced to $1,000,000, which is consistent with previous decisions by the Board including Order No.'s P.U. 7 (1996-1997), P.U. 36 (1998-1999), P.U. 19 (2003), P.U. 32 (2007), P.U. 43 (2009), and P.U. 13 (2013). During 2016 the Company deferred $853,000 in actual costs.

- **2016 Revenue Surplus:** In Order No. P.U. 25 (2016), the Board approved the final customer rates resulting from the Company's 2016/2017 General Rate Application. This revenue surplus includes an amortization for 2016 resulting from the July 1, 2016 implementation. The Company's 2016/2017 GRA Compliance Report filed on June 17, 2016 resulted in the revenue surplus of $2,580,000. In 2016 this resulted in a net revenue requirement impact of $2,064,000 (surplus of $2,580,000 less amortization of $516,000).

## Proposed Regulatory Deferrals

Newfoundland Power has proposed, in the 2019/2020 General Rate Application, that the Board approve the following additional deferrals for 2019 and 2020:

(a) amortize the recovery over a 34-month period of an estimated $1,000,000 in Board and Consumer Advocate costs related to the Application, in addition to excess costs being collected through the RSA; and,

(b) amortize forecast 2019 revenue surplus of an estimated amount of $919,000 over a 34-month period.

We conducted an examination of each of the regulatory deferral accounts and amortizations proposed in this Application.

- **<u>2019/2020 General Rate Application Costs:</u>** With respect to the costs relating to the 2019/2020 GRA, the Company is proposing that these costs be recovered in customer rates evenly over a 34-month period ending December 31, 2021. This is consistent with previous decisions by the Board including Order No.'s P.U. 7 (1996-1997), P.U. 36 (1998-1999), P.U. 19 (2003), P.U. 32 (2007), P.U. 43 (2009), P.U. 13 (2013), and P.U. 18 (2016). The Company estimates costs associated with the 2019/2020 General Rate Application proposal will have a forecast revenue requirement impact of $294,000 and $353,000 in the years 2019 and 2020 respectively, and the remaining amount during 2021.

- **<u>2019 Revenue Surplus:</u>** Based upon a March 1, 2019 implementation, customer rates designed to recover the proposed 2020 revenue requirement would result in a $919,000 over recovery of the proposed 2019 revenue requirement. The Company is proposing to amortize the amount over 34-months commencing March 1, 2019 and ending December 31, 2021. This is consistent with the process to recover the 2013 revenue shortfall approved in Order No. P.U. 13 (2013) and 2016 revenue surplus in Order No. P.U. 25 (2016).

**Based on our review and analysis, nothing has come to our attention to indicate the regulatory deferrals and amortizations included in the Application are unreasonable or not in accordance with Board Orders.**

# Conservation and Demand Management ("CDM") Cost Deferral

In Order No. P.U. 13 (2013) the Board approved the definition for the Conservation and Demand Management Cost Deferral Account and the amortization of annual customer energy conservation program costs over seven years with recovery through the RSA. The definition for the CDM cost deferral account is as follows:

> *"This account shall be charged with the costs incurred in implementing the CDM Program Portfolio. These costs include the CDM Program Portfolio costs incurred by Newfoundland Power for: detailed program development, promotional materials, advertising, pre and post customer installation checks, incentives, processing applications and incentives, training of employees and trade allies, and program evaluation costs. This account shall also be charged the costs of major CDM studies such as comprehensive customer end use surveys and CDM potential studies that cost greater than $100,000. Transfers to, and from, the proposed account will be tax-effected. This account will maintain a linkage of all costs recorded in the account to the year the cost was incurred. Recovery of annual amortizations of costs in this account shall be through the Company's Rate Stabilization Plan or as otherwise ordered by the Board."*

According to information filed with the Application, the Company and Newfoundland and Labrador Hydro began implementing an updated 5-year energy conservation plan in 2016. This resulted in the creation of the *Five-Year Energy Conservation Plan: 2016-2020.* The primary changes in the plan relate to (i) expansion of the Business Efficiency Program and Instant Rebates program; (ii) introduction of a new residential benchmarking program to encourage behavioural change among customers; (iii) discontinuation of certain residential incentives; and (iv) development of an initiative to educate customers on mini-split heat pumps.

The programs included in the *Five-Year Energy Conservation Plan: 2016-2020* were screened using the Total Cost test and the Program Administrator Cost test. According to the Company, these are standard metrics that assess the cost-effectiveness of conservation programs and facilitate program planning. Prior to this plan customer energy conservation programs were evaluated using the Total Cost test and the Rate Impact Measure test. The newly adopted screening methods included in the plan were approved by the Board in Order No. P.U. 18 (2016).

The Company is currently at the midway point of the *Five-Year Energy Conservation Plan: 2016-2020*, with the expected changes in programming over the remainder of the plan to include: (i) conclusion of the Instant Rebates program, and residential benchmarking program in 2019; (ii) continued expansion of the Business Efficiency Program; and (iii) increased emphasis on customer education through social media, websites, and customer events.

The following tables provide the forecast energy savings and costs (Page 2-13 of the GRA) for the period 2013 to 2017 and forecast costs (Page 2-16 of the GRA) for the Company's customer conservation programs for 2016 to 2020F:

**Table 2: Customer Conservation Programs – 2013-2017**

| | 2013 | 2014 | 2015 | 2016 | 2017 |
|---|---|---|---|---|---|
| Costs ($000s) | $ 3,654 | $ 5,289 | $ 5,318 | $ 7,639 | $ 7,378 |
| Energy Savings (GWh) | 36.3 | 50.0 | 66.6 | 91.8 | 123.7 |

**Table 3: Customer Conservation Programs Costs 2016-2020P**

| ($000s) | 2016 | 2017 | 2018F | 2019P | 2020P |
|---|---|---|---|---|---|
| General | $ 439 | $ 620 | $ 623 | $ 825 | $ 693 |
| Program | 7,200 | 6,758 | 6,701 | 6,895 | 4,065 |
| **Total** | **$ 7,639** | **$ 7,378** | **$ 7,324** | **$ 7,720** | **$ 4,758** |

The Company has noted that the annualized energy savings from customer conservation programs more than tripled from 2013 to 2017. Additionally, costs related to customer conservation programs are forecasted to average approximately $7,500,000 per year for 2018 and 2019, with costs to decline to approximately $4,800,000 in 2020.

The following table provides a breakdown of operating costs before tax that include the customer energy conservation costs for 2016 to 2020F as provided by the Company, and agreed to total customer energy conservation costs presented in the previous table:

**Table 4: Customer Energy Conservation Costs 2016-2020P**

| ($000s) | 2016 | 2017 | 2018F | 2019P | 2020P |
|---|---|---|---|---|---|
| **General Expenses** | | | | | |
| Regular and Standby | $ 228 | $ 297 | $ 272 | $ 418 | $ 294 |
| Temporary | - | 2 | - | - | - |
| Overtime | 2 | 4 | - | - | - |
| Travel | 9 | 17 | 21 | 34 | 18 |
| Miscellaneous | 86 | 127 | 108 | 140 | 140 |
| Education, Training, Employee Fees | 2 | 15 | 15 | 20 | 20 |
| Postage and Freight | - | 1 | - | - | - |
| Advertising | 112 | 157 | 207 | 213 | 221 |
| **Total General Expenses** | **$ 439** | **$ 620** | **$ 623** | **$ 825** | **$ 693** |
| | | | | | |
| **Program Expenses** | | | | | |
| Regular and Standby | $ 1,030 | $ 1,157 | $ 1,154 | $ 1,141 | $ 910 |
| Temporary | 22 | 32 | 60 | 60 | 60 |
| Overtime | 46 | 49 | 74 | 86 | 86 |
| Operating Materials | 3 | 2 | - | - | 34 |
| Travel | 28 | 40 | 52 | 53 | - |
| Tools and Clothing Allowance | 1 | - | - | - | 200 |
| Miscellaneous | 204 | 179 | 218 | 209 | 1,845 |
| Conservation (Incentives) | 4,253 | 2,981 | 2,873 | 3,038 | 24 |
| Education, Training, Employee Fees | 7 | 10 | 24 | 24 | 113 |
| Other Company Fees | 552 | 1,178 | 1,231 | 1,170 | - |
| Postage and Freight | 2 | 1 | - | - | 793 |
| Advertising | 1,052 | 1,129 | 1,015 | 1,114 | - |
| **Total Program Expenses** | **$ 7,200** | **$ 6,758** | **$ 6,701** | **$ 6,895** | **$ 4,065** |
| | | | | | |
| **Total Expenses** | **$ 7,639** | **$ 7,378** | **$ 7,324** | **$ 7,720** | **$ 4,758** |

The following table provides the impact of the proposed annual customer energy conservation program cost deferrals and amortizations for 2017 to 2020P:

**Table 5: Conservation Program Costs – Forecast Deferrals and Amortizations 2017–2020P**

| ($000s) | 2017 | 2018F | 2019P | 2020P |
|---|---|---|---|---|
| Deferrals | $ (6,758) | $ (6,701) | $ (6,895) | $ (4,065) |
| Amortizations | $ 2,741 | $ 3,707 | $ 4,665 | $ 5,650 |

Amortization presented in the table is calculated over seven years as approved in Order No. P.U. 13 (2013). Amortization is forecast to increase through this period from $2,741,000 in 2017 to $5,650,000 in 2020P. Further in Order No. P.U. 13 (2013), the Company is recovering these costs through annual RSA factor adjustments which increases customer rates as opposed to being included in revenue requirements which would be reflected in the Company's base rates.

**Based upon our review of the Company's Conservation and Demand Management Cost Deferral Account, we note amortizations of conservation deferrals and transfers to the RSA presented in the GRA are accurate based on an amortization period of seven years approved by the Board.**

# Return on Rate Base and Equity, Capital Structure and Interest Coverage

## Calculation of Average Rate Base

The Company's calculations of its forecast average rate base for the years ending December 31, 2018, 2019 and 2020 are included on Exhibit 3 Page 5 of 9 and Exhibit 6 of the pre-filed evidence. Our procedures with respect to verifying the calculation of average rate base were directed towards the assessment of the reasonableness of the data incorporated in the calculations and the methodology used by the Company. Specifically, the procedures which we performed included the following:

- agreed all carry-forward data to supporting documentation including prior years audited financial statements and internal accounting records, where applicable;

- agreed forecast data (capital expenditures; depreciation; etc.) to supporting documentation to ensure it is internally consistent with pre-filed evidence and other areas of the forecast;

- checked the clerical accuracy of the continuity of the rate base as forecast for 2018, 2019 and 2020;

- recalculated the forecast rate base for 2018, 2019 and 2020; and,

- agreed the methodology used in the calculation of the average rate base to the Public Utilities Act and relevant Board Orders to ensure it is in accordance with established policy and procedure.

The following table summarizes the 2019 and 2020 average rate base as existing and as proposed:

**Table 6: Average Rate Base 2019-2020**

| | 2019 | | | | 2020 | | | |
|---|---|---|---|---|---|---|---|---|
| **(000's)** | **Existing** | **Impact** | | **Proposed** | **Existing** | **Impact** | | **Proposed** |
| Net Plant Investment | $ 1,091,011 | $ 1,171 | (1) | $ 1,092,182 | $ 1,123,671 | $ 3,518 | (1) | $ 1,127,189 |
| Add: | | | | | | | | |
| Defined Benefit Pension Costs | 91,210 | - | | 91,210 | 95,350 | - | | 95,350 |
| Cost Recovery Deferrals | | | | | | | | |
| Credit Facility Costs | 68 | (26) | (2) | 42 | 39 | (39) | (2) | - |
| Hearing Costs | - | 353 | (3) | 353 | - | 530 | (3) | 530 |
| Conservation | 16,993 | - | | 16,993 | 17,219 | - | | 17,219 |
| Weather Normalization Reserve (a) | (136) | 136 | | - | - | - | | - |
| Customer Finance Programs | 1,545 | - | | 1,545 | 1,575 | - | | 1,575 |
| | 109,680 | 463 | | 110,143 | 114,183 | 491 | | 114,674 |
| Deduct: | | | | | | | | |
| Weather Normalization Reserve (a) | - | 136 | | 136 | - | - | | - |
| Other Post Employee Benefits | 57,846 | - | | 57,846 | 61,415 | - | | 61,415 |
| Customer Security Deposits | 1,066 | - | | 1,066 | 1,066 | - | | 1,066 |
| Accrued Pension Obligation | 5,174 | - | | 5,174 | 5,469 | - | | 5,469 |
| Accumulated Deferred Income Taxes | 6,977 | - | | 6,977 | 9,808 | - | | 9,808 |
| 2019 Revenue Surplus | - | 227 | (4) | 227 | - | 340 | (4) | 340 |
| | 71,063 | 363 | | 71,426 | 77,758 | 340 | | 78,098 |
| Average Rate Base Before Allowances | 1,129,628 | 1,271 | | 1,130,899 | 1,160,096 | 3,669 | | 1,163,765 |
| Cash Working Capital Allowance | 8,212 | 1,514 | (5) | 9,726 | 8,169 | 1,648 | (5) | 9,817 |
| Materials and Supplies Allowance | 5,925 | (257) | (6) | 5,668 | 6,037 | (262) | (6) | 5,775 |
| Average Rate Base at Year End | **$ 1,143,765** | **$ 2,528** | | **$ 1,146,293** | **$ 1,174,302** | **$ 5,055** | | **$ 1,179,357** |

(a) The Company has presented the balance as a negative figure in the additions from rate base in Exhibit 3 of the Application. In effect, this is an addition to rate base and has been presented as an addition to average rate base for presentation purposes in this table.

(1) Net Plant Investment – The increase of net plant investment in proposed compared to existing relates to the proposed changes in capitalization of pension costs. The increase in net additions is approximately $2,296,000 and $2,311,000 for 2019 and 2020 respectively, due to the proposed change to the capitalization of pensions which will result in pension costs being capitalized at a 46% rate versus the current 11% rate. This proposal will increase the capitalization of pensions reflected in the calculation of General Expenses Capitalized (GEC). The impact on average rate base for 2019 and 2020 is $1,171,000 and $3,518,000 correspondingly after accounting for depreciation.

(2) Credit Facility Costs – For test year revenue requirement purposes, unamortized credit facility costs are included in the calculation of the Company's weighted average cost of

capital. Between test years, any additional costs incurred associated with amendments to the credit facility are reflected in rate base as they have not yet been reflected in the Company's weighted average cost of capital and/or customer rates. Impact on average rate base for 2019 and 2020 is $26,000 and $39,000 decreases respectively.

(3) The increase in Cost Recovery Deferrals – Hearing Costs relates to the expectation that $1,000,000 will be incurred by the Board and Consumer Advocate related to the Application. The Company is proposing these costs be recovered in customer rates evenly over a 34-month period from March 1, 2019 to December 31, 2021, and costs in excess go through the RSA.

(4) Based upon a March 1, 2019 implementation, customer rates would result in $919,000 over recovery of the proposed 2019 revenue requirement. In this Application, the Company is proposing to amortize this amount over 34-months commencing March 1, 2019 and ending December 31, 2021. The proposed increase in amortization has an impact on average rate base for 2019 and 2020 of $227,000 and $340,000 respectively.

(5) The increase in the cash working capital allowance is a result of an increase in the cash working capital factor from 1.3% for 2016/2017 test years to 1.8% for the 2019/2020 test years as a result of an increase in the net lag days relating to collection of revenue and payment of costs. This increase is partially offset by a decrease in the HST factor in the cash working capital.

(6) The decrease in the materials and supplies allowance is a result of a higher expansion factor deduction used in the proposed average rate base. The Company has revised the Materials Allowance expansion factor to 24.05% for the 2019/2020 test years versus 20.61% calculated for the 2016/2017 test years. The Company noted in pre-filed evidence that the change in expansion was based on a review of actual inventories in 2017 used for expansion projects.

**Based upon the results of the above procedures, we did not note any discrepancies in the calculation of the average rate base, and therefore conclude that the forecast average rate base included in the Company's pre-filed evidence is in accordance with established practice. We also conclude that the proposed average rate base accurately reflects the Company's proposals with respect to the change in accounting for pension expense, regulatory deferral accounts and the updated calculations related to the rate base allowances.**

**Return on Rate Base**

Our procedures with respect to verifying the calculation of forecast return on average rate base included agreeing the data in the calculation to supporting documentation and recalculating the forecast rate of return to ensure it is in accordance with established practice and Board Orders.

The following table provides the 2016 to 2017 actual return on rate base, the Company's forecast rate of return on rate base for 2018 to 2020, the Company's proposed return on rate base for 2019 and 2020 and the upper and lower end of range as set by the Board:

**Table 7: Return on Average Rate Base 2016-2020**

| | Actual | | Forecast | | | Proposed | |
|---|---|---|---|---|---|---|---|
| | 2016 | 2017 | 2018 | 2019 | 2020 | 2019 | 2020 |
| **Actual Return on Average Rate Base** | 7.31% | 7.22% | 7.00% | 6.34% | 6.09% | 7.47% | 7.49% |
| **Upper End of Range set by the Board** | 7.39% | 7.37% | 7.22% | | | 7.65% | 7.67% |
| **Lower End of Range set by the Board** | 7.03% | 7.01% | 6.86% | | | 7.29% | 7.31% |

In Order No. P.U. 16 (1998-99) and Order No. P.U. 36 (1998-99) the Board ordered the use of the automatic adjustment formula to set an appropriate rate of return on rate base for the Company on an annual basis ("the Formula"). In Order No. P.U. 25 (2011) and Order No. P.U. 18 (2016) the Board approved the suspension of the operation of the Formula to establish a rate of return on rate base. The appropriateness of the Company's proposal to discontinue the use of the Formula will be reviewed by the cost of capital experts participating in this hearing.

In Order No. P.U. 25 (2016) the Board approved a rate of return on average rate base for 2016 of 7.21% in a range of 7.03% to 7.39% and a rate of return on average rate base for 2017 of 7.19% in a range of 7.01% to 7.37%. In Order No. P.U. 41 (2017) the Board approved a 2018 rate of return on average rate base of 7.04%, in a range of 6.86% to 7.22%. The Company is proposing the Board approve a return on average rate base for 2019 of 7.47%, within a range of 7.29% to 7.65% and for 2020 of 7.49%, within a range of 7.31% to 7.67%.

**Based upon the results of the above procedures, we did not note any discrepancies in the Company's calculation of the return on average rate base, and therefore conclude that the forecast return on average rate base included in the Company's pre-filed evidence has been calculated in accordance with established practice. We also conclude that the proposed rate of return on average rate base accurately reflects the proposals in this Application as well as the Company's targeted return on equity of 9.50% which will be addressed by cost of capital experts participating in this hearing.**

**Capital Structure**

In Order No. P.U. 43 (2009) the Board confirmed its previous position regarding the capital structure for Newfoundland Power comprised of 45% equity, 54% debt and 1% preferred equity. In Order No.'s P.U. 13 (2013) and P.U. 18 (2016), the Board maintained its position for equity not to exceed 45% of capital structure.

Average forecast common equity for 2018 through 2020, including the proposed average common equity for 2019 and 2020 per the pre-filed evidence, is below the approved maximum, and accordingly, no calculation for deeming excess common equity as preferred equity is required.

In its pre-filed evidence, the Company is proposing to maintain a capital structure which is consistent with the structure established by Order No.'s P.U. 16 (1998-99), P.U. 19 (2003), P.U. 32 (2007), P.U. 43 (2009), P.U. 13 (2013), and P.U. 18 (2016).

Based on our recalculations of the components of the capital structure, the Company's projected average capital structure for 2016 through 2020 is as follows:

**Table 8: Capital Structure 2016-2020**

| | Actual 2016 | Actual 2017 | Forecast 2018 | Forecast 2019 | Forecast 2020 | Proposed 2019 | Proposed 2020 |
|---|---|---|---|---|---|---|---|
| Debt | 54.17% | 54.22% | 54.76% | 54.48% | 54.33% | 54.38% | 54.28% |
| Preferred Equity | 0.84% | 0.82% | 0.80% | 0.78% | 0.76% | 0.78% | 0.76% |
| Common Equity | 44.99% | 44.96% | 44.44% | 44.74% | 44.91% | 44.84% | 44.96% |
| Total | 100.00% | 100.00% | 100.00% | 100.00% | 100.00% | 100.00% | 100.00% |

The above table shows that the Company's forecast average common equity for 2018 to 2020 is below the 45% maximum approved by the Board. The debt portion of the cost of capital for 2019 and 2020 proposed is 5.81% and 5.84% respectively. We recalculated the debt portion of the cost of capital using the average debt, included in the average capital structure above, and the finance charges presented in Exhibit 5 (Page 7 of 9).

**The proposed capital structure for 2019 and 2020 is consistent with the position confirmed by the Board in Order No. P.U. 18 (2016). The above calculations of capital structure are consistent with Exhibit 3 (Page 6 of 9) and Exhibit 5 (Page 6 of 9) presented in the 2019/2020 GRA.**

**Calculation of Average Common Equity and Return on Average Common Equity**

Newfoundland Power has noted that, based on expert evidence filed with the GRA which indicates a fair return, it is targeting a 2019 and 2020 return on equity of 9.5%.

Similar to the approach used to verify the rate base, our procedures in this area focused on verification of the data incorporated in the calculations and on the methodology used by the Company. Specifically, the procedures which we performed included the following:

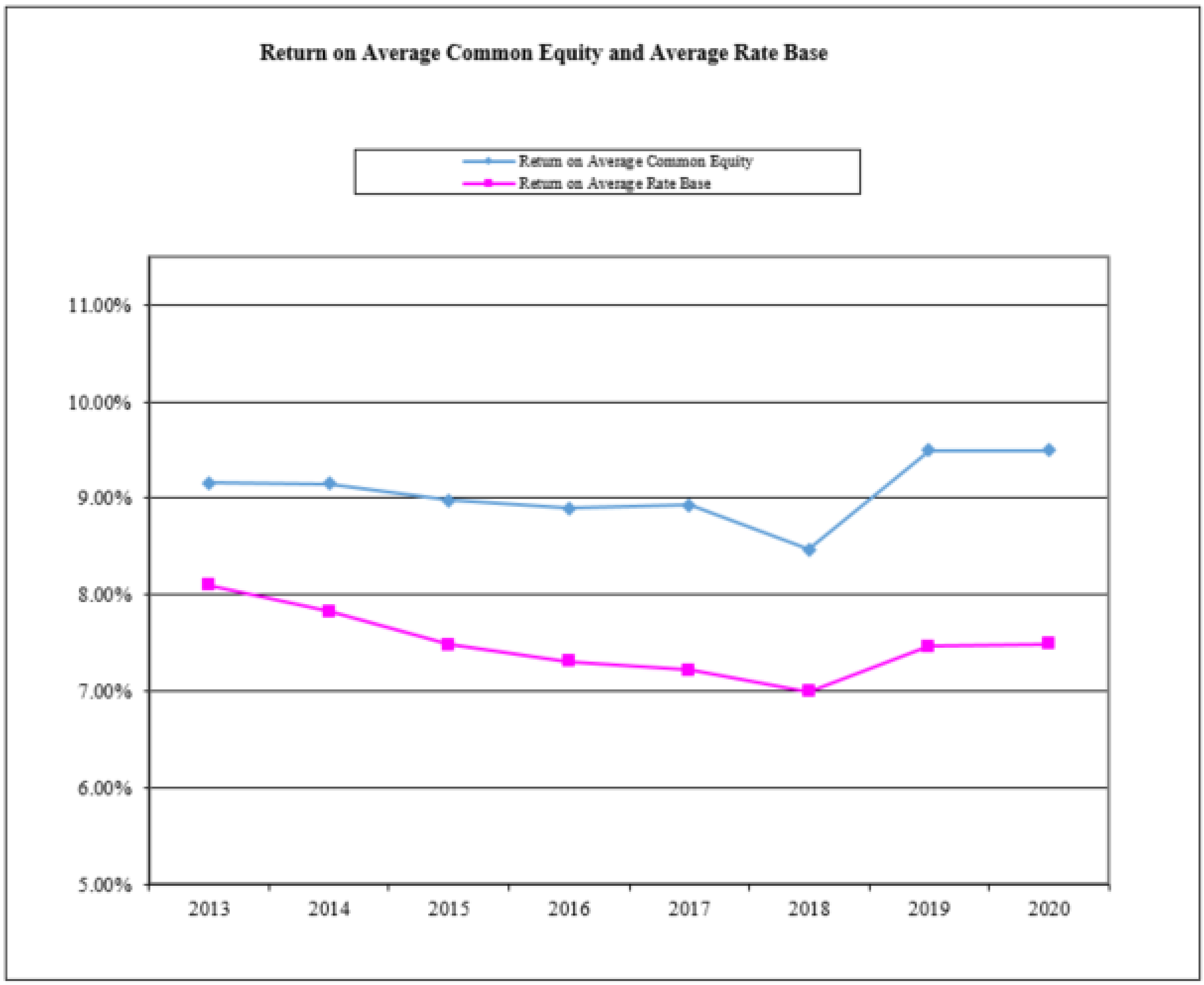
- agreed all carry-forward data to supporting documentation, including audited financial statements and internal accounting records where applicable;

- agreed forecast data (earnings applicable to common shares; dividends; regulated earnings; etc.) to supporting documentation to ensure it is internally consistent with the pre-filed evidence and other areas of the forecast;
- checked the clerical accuracy of the continuity of common equity; and,
- recalculated the forecast rate of return on common equity for 2018, 2019 and 2020 to ensure it is in accordance with established practice.

The following is a comparison of the actual return on average common equity from 2013 to 2017, forecast for 2018 and proposed 2019 and 2020 with the actual return on average rate base for 2013 to proposed 2020.

**Table 9: Average Common Equity vs. Return on Average Rate Base 2013-2020**

| | | | | | | Forecast | Proposed | Proposed |
|---|---|---|---|---|---|---|---|---|
| | **2013** | **2014** | **2015** | **2016** | **2017** | **2018** | **2019** | **2020** |
| **Return on Average Common Equity** | 9.16% | 9.15% | 8.98% | 8.90% | 8.93% | 8.47% | 9.50% | 9.50% |
| **Return on Average Rate Base** | 8.10% | 7.83% | 7.48% | 7.31% | 7.22% | 7.00% | 7.47% | 7.49% |
| **Spread between actual returns** | 1.06% | 1.32% | 1.50% | 1.59% | 1.71% | 1.47% | 2.03% | 2.01% |




As demonstrated by the graph above, the proposed 2019 and 2020 return on average rate base results in an increase in the spread between the return on average common equity and return on average rate base as compared to the previous years shown.

**Based upon the results of the above procedures, we did not note any discrepancies in the calculation of the forecast and proposed rate of return on average common equity for 2018, 2019 and 2020. The 2019 and 2020 proposed rate of return on common equity will be addressed by the cost of capital experts participating in this hearing.**

**Interest Coverage**

The level of interest coverage experienced by the Company in 2017 and as forecasted, is as follows:

**Table 10: Interest Coverage 2017-2020**

| (000's) | Actual 2017 | Forecast 2018 | Existing 2019 (1) | Proposed 2019 | Existing 2020 | Proposed 2020 |
|---|---|---|---|---|---|---|
| Income before taxes | $ 54,408 | $ 51,587 | $ 43,462 | $ 60,766 | $ 40,154 | $ 62,680 |
| Interest on long term debt | 35,013 | 35,789 | 35,374 | 35,374 | 37,080 | 37,080 |
| Other interest | 659 | 715 | 1,353 | 1,661 | 754 | 1,195 |
| Capitalized interest | (1,025) | (984) | (1,020) | (1,046) | (1,039) | (1,070) |
| Amortization of debt issue expenses | 234 | 232 | 224 | 224 | 219 | 219 |
| Total | 89,289 | 87,339 | 79,393 | 96,979 | 77,168 | 100,104 |
| Interest on long term debt | 35,013 | 35,789 | 35,374 | 35,374 | 37,080 | 37,080 |
| Other interest | 659 | 715 | 1,353 | 1,661 | 754 | 1,195 |
| Amortization of debt issue expenses | 234 | 232 | 224 | 224 | 219 | 219 |
| Total | $ 35,906 | $ 36,736 | $ 36,951 | $ 37,259 | $ 38,053 | $ 38,494 |
| **Interest coverage (times)** | **2.5** | **2.4** | **2.1** | **2.6** | **2.0** | **2.6** |

(1) We calculated an interest coverage of 2.1 for 2019 existing, however Exhibit 3 page 1 of 9 presents 2.0.

(2) Interest coverage is calucated at the company level, including both regulated and non-regulated operations.

In Order No. P.U. 43 (2009) the Board was satisfied with the Company's interest coverage ratio of 2.5 times given the Company's capital structure and return on regulated equity. In 2015, 2016, and 2017 as per the Company's Exhibit 3 (page 1 of 9), interest coverages increased from 2.3 to 2.4, and 2.5 respectively. The forecast ratios for 2018, 2019 and 2020 under existing rates are 2.4, 2.1 and 2.0 times respectively. As indicated above, the proposals included in this Application result in interest coverage for 2019 and 2020 of 2.6 in both years.

The level of interest coverage will be reviewed by the cost of capital experts participating in this hearing.

## Forecasting Methodology and Assumptions

According to Newfoundland Power, the Company's forecast of revenue and expenses for 2018, 2019 and 2020 is based on the expected operating and capital requirements, as well as assumptions, which reflect the best estimate of future economic conditions and events.

Our approach to this item of the terms of reference focused on three main objectives:

1. to assess the incorporation of assumptions into the forecast presented by management with regard to future economic conditions and events;
2. to assess the major assumptions disclosed in Exhibits 3 and 5 of the Application for consistency with forecast information reflected throughout the Application; and,
3. to assess the methodology used by the Company for forecasting revenues and expenses.

*Assessment of assumptions*

The economic assumptions used in preparing the customer and energy sales forecast are based on the Conference Board of Canada's (CBOC) Provincial forecast, long-term forecast, dated January 19, 2018. According to the Company, the CBOC is the primary provider of economic information for development of the Company's Customer, Energy and Demand Forecast, dated April 2018.

As a result of our review, we have determined that the assumptions used by management in forecasting revenue and expenses are based upon and incorporate data from an independent source, where applicable, and are consistent with the information included in the pre-filed evidence.

*Incorporation of assumptions into forecast*

The incorporation of the stated assumptions into the forecast was assessed through a review of the exhibits included in the pre-filed evidence and other supporting schedules and information provided by the Company. Based upon the results of our procedures we can confirm that the assumptions disclosed in Exhibits 3 and 5 of the GRA are consistent with the forecast information included throughout the GRA.

*Methodology*

The Customer, Energy and Demand Forecast forms the foundation of the Company's planning process. The forecast is a key input in developing estimates of capital expenditures required, and directly addresses the estimation of future revenue from electrical sales and expenditures on purchased power.

The Company's methodologies for forecasting as described in the Customer, Energy and Demand Forecast are consistent with those used in the 2016/2017 GRA.

Once the forecast has been developed, it is reviewed in detail by the Executive group. Any required changes to the forecast are communicated and made by the Finance department of the Company. Once the forecast has been finalized, it is forwarded to the Internal Audit group for quality assurance purposes. The Company indicated that the GDP deflator was a key assumption used in developing the 2018, 2019 and 2020 forecast of non-labour operating expenses. The 2018 to 2020 forecasts of capital expenditures are based on the 2018 capital budget application submitted to the Board and approved in Order No. P.U. 37 (2017).

**As a result of our review, we have determined that the overall methodology used by the Company for estimating revenue, expenses and net earnings is similar to the process and methodology used in the 2016/2017 GRA. Our observations and comments with respect to individual expense estimates and revenue from rates are included within the operating expense and proposed revenue from rates sections of our report.**

## Capital Expenditures

The following table details the actual versus budgeted capital expenditures from 2015 to 2017, and the forecast figures for 2018 to 2020.

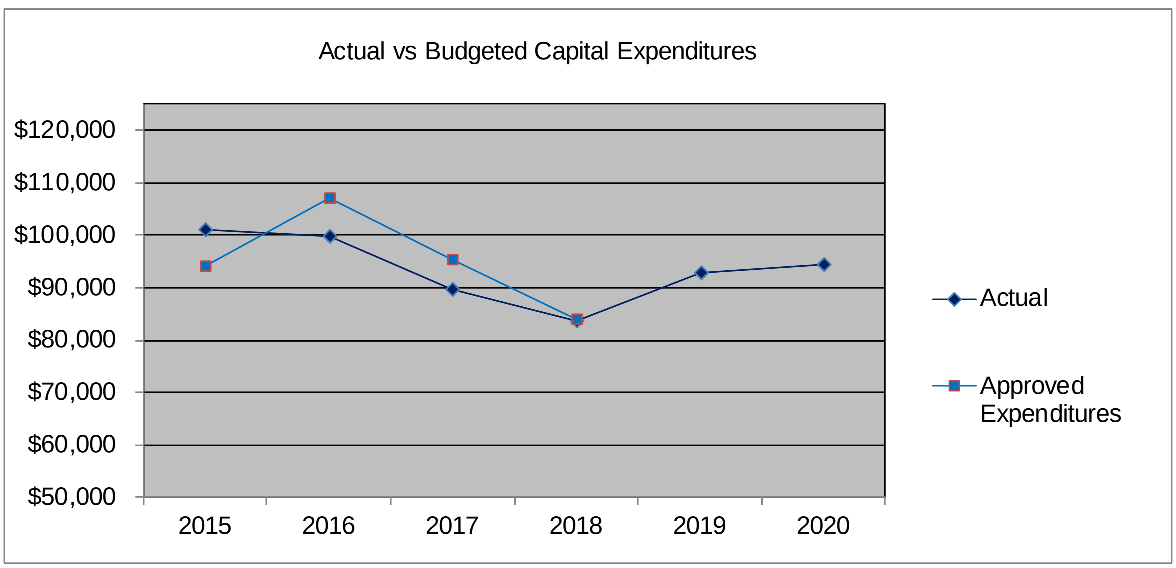
The table and graph below demonstrates that in 2015 the Company was over budget on capital expenditures and for 2016 and 2017 the Company was under budget on capital expenditures.

We have reviewed the significant variances from 2015 to 2017 as part of our annual financial reviews and our comments on these variances are contained in our annual review reports filed with the Board.

**Table 11: Capital Expenditures 2015-2020E**

| **($000s)** | **2015** | **2016** | **2017** | **2018E** (a) | **2019E** (a) | **2020E** (a) |
|---|---|---|---|---|---|---|
| **Actual** (b, d) | $ 97,155 | $ 92,727 | $ 83,921 | $ 83,719 | $ 92,777 | $ 94,446 |
| **Actual Carry Over** (c) | 3,861 | 7,043 | 5,770 | - | - | - |
| | $ 101,016 | $ 99,770 | $ 89,691 | $ 83,719 | $ 92,777 | $ 94,446 |
| **Approved Expenditures** | $ 94,211 | $ 107,028 | $ 95,521 | $ 83,876 | N/A | N/A |
| **Over (Under) Budget** | 7.22% | -6.78% | -6.10% | -0.19% | N/A | N/A |

(a) The actual figures for 2018 to 2020 are the forecast based on existing figures.
(b) Actual represents the actual expenditures on projects approved in that year.
(c) Carry over respresents actual expenditures in subsequent years on projects approved in that year except the 2017 forecast carry over. The Company provided the presented figures.
(d) Actual figures disclosed in the GRA (Table 2-14) excluded expenditures for unforeseen items and general expenses capitalized. These amounts were subsequently requested from the Company and have been included in the figures presented.



In Order No. P.U. 37 (2017) the Board approved expenditures of $83,876,000 for the 2018 capital program. This represents a decrease of approximately 12.19% compared to the 2017 approved capital expenditures of $95,521,000.

The reason for the decrease is mainly due to reduction in customer requirements and completion of the deployment of Automated Meter Readers. This decrease is primarily observed in the Distribution category of capital expenditures of the Company. From 2015 to 2017, the capital expenditures under Distribution averaged approximately $46 million per year, for forecast 2018 to 2020 years it averages approximately $39 million per year.

The Company's annual capital programming continues to focus efforts on replacement and refurbishment of existing assets. Over 50% of the Company's forecasted capital expenditures relate to the replacement or refurbishment of existing assets.

The Company is proposing forecast capital expenditures of $92,777,000 for 2019 which is an increase of 10.82% in comparison to the approved capital expenditures in 2018. The Company is also proposing the forecast capital expenditures of $94,446,000 for 2020, which is an increase of 1.80% in comparison to the proposed forecast for 2019. Capital expenditures for 2018 through 2020 are based on the 2018 Capital Budget Application approved on November 6, 2017, adjusted for known carryovers in 2018.

The table below provides the 2019 and 2020 forecast under existing and proposed methodologies for capital expenditures:

**Table 12: Capital Expenditures - 2019 and 2020**

| **($000s)** | | **2019** | | **2020** |
|---|---|---|---|---|
| Existing Capital Expenditures | $ | 92,777 | $ | 94,446 |
| Pension Adjustment | | 2,296 | | 2,311 |
| Proposed Capital Expenditures | **$** | **95,073** | **$** | **96,757** |

The pension adjustment is based on the Company's proposal to change the capitalization of pensions which will result in pension costs being capitalized at a 46% rate versus the current 11% rate. This proposal will increase the capitalization of pensions reflected in the calculation of general expenses capitalized. This proposal was discussed previously within another section of the report.

On July 13, 2018 the Company filed its 2019 Capital Budget Application. In this application the 2019 and 2020 capital expenditures are forecast to be $93,304,000 and $97,408,000, respectively. These capital expenditures exclude the Company's proposal to change the capitalization of pensions.

# Depreciation

In Order No. P.U. 18 (2016) the Board approved Newfoundland Power's use of the depreciation rates and methodology, including the approval of the accumulated depreciation reserve variance to be amortized over the average remaining service life of the related assets, as recommended in the 2014 Depreciation Study completed by Gannett Fleming on the calculation of its depreciation expense effective January 1, 2016.

The following table summarizes the depreciation expense for the years 2016 to 2020:

**Table 13: Depreciation Expense 2016-2020**

| ($000s) | 2016A | 2017A | 2018F | 2019E | 2019P | 2020E | 2020P |
|---|---|---|---|---|---|---|---|
| **Depreciation Expense** | $ 55,190 | $ 57,487 | $ 59,801 | $ 62,314 | $ 62,350 | $ 64,797 | $ 64,908 |
| **% Change - year over year** | | 4.2% | 4.0% | 4.2% | 4.3% | 4.0% | 4.1% |

The increase in annual depreciation expense for the years 2016 to 2020 is primarily the result of the Company's annual capital expenditures.

The difference between existing and proposed 2019 and 2020 is due to the proposed pension capitalization.

Depreciation amounts and rates incorporated in the 2019 and 2020 forecast are based upon the recommendations of the 2014 Depreciation Study. Specifically we performed the following:

- agreed all depreciation rates to those recommended in the depreciation study and the Company's pre-filed evidence; and

- recalculated the Company's estimate of depreciation expense for 2019 and 2020.

**Based on our review of depreciation expense, we conclude that the depreciation rates used to calculate the proposed forecast for 2019 and 2020 agree to those recommended in the 2014 Depreciation Study and the Company's pre-filed evidence. We have recalculated the depreciation expense for 2019 and 2020 without identifying any material errors and conclude that the depreciation expense is calculated in accordance with the rates prescribed in the 2014 Depreciation Study.**

# 2019/2020 Test Year Financial Forecast

Based on the evidence included in Exhibit 9 of the Company's pre-filed evidence, Newfoundland Power has indicated it requires an increase in revenue requirement of approximately $6.2 million in 2019 and $8.0 million in 2020. This increase is based on the proposals that the Company has put forward relating to regulatory deferrals, a rate of return on average rate base of 7.47% in 2019 and 7.49% in 2020 and a rate of return on common equity of 9.5% in 2019 and 2020. The factors contributing to the increase can be summarized as follows:

**Table 14: Components of 2019 Proposed Rate Change**

**Components of 2019 Proposed Rate Change**

| (000's) | Existing (Including elasticity adjustment) | Changes | Proposed | Rate Change % |
|---|---|---|---|---|
| **Return on Rate Base** | $ 72,554 | $ 13,081 | $ 85,635 | 2.0 |
| **Other Costs** | | | | |
| Power Supply Costs | 430,627 | (678) | 429,949 | (0.1) |
| Operating Costs | 64,682 | (2,003) | 62,679 | (0.3) |
| Employee Future Benefit Costs | 9,080 | - | 9,080 | - |
| Deferred Cost Recoveries and Amortizations | - | 649 | 649 | 0.1 |
| Depreciation | 62,314 | 36 | 62,350 | 0.0 |
| Income Taxes | 15,814 | 4,506 | 20,320 | 0.7 |
| | 582,517 | 2,510 | 585,027 | |
| **Total Costs and Return** | 655,071 | 15,591 | 670,662 | |
| **Adjustments** | | | | |
| Other Revenue | (5,584) | (28) | (5,612) | 0.0 |
| Interest on Security Deposits | 18 | - | 18 | - |
| Energy Supply Cost Variance Adjustments | 4,502 | (3,438) | 1,064 | (0.5) |
| Other | 1,834 | (6,499) | (4,665) | (1.0) |
| | 770 | (9,965) | (9,195) | |
| **Elasticity Adjustment** | (607) | 607 | - | 0.1 |
| **2019 Revenue Requirement from Rates** | **655,234** | **6,233** | **661,467** | 0.9 |
| **RSA** | (11,496) | 12 | (11,484) | 0.0 |
| **MTA** | 18,043 | 157 | 18,200 | 0.0 |
| **Elasticity Adjustment** | (4) | 4 | | 0.0 |
| **Billed to Customers** | **$ 661,777** | **$ 6,406** | **$ 668,183** | 1.0 |

**Table 15: Components of 2020 Proposed Rate Change**

| Components of 2020 Proposed Rate Change | | | | |
|---|---|---|---|---|
| **(000's)** | **Existing (Including elasticity adjustment)** | **Changes** | **Proposed** | **Rate Change %** |
| **Return on Rate Base** | $ 71,508 | $ 16,854 | $ 88,362 | 2.5 |
| **Other Costs** | | | | |
| Power Supply Costs | 430,644 | (1,500) | 429,144 | (0.2) |
| Operating Costs | 66,571 | (1,961) | 64,610 | (0.3) |
| Employee Future Benefit Costs | 7,566 | - | 7,566 | - |
| Deferred Cost Recoveries and Amortizations | - | (324) | (324) | (0.0) |
| Depreciation | 64,797 | 111 | 64,908 | 0.0 |
| Income Taxes | 14,985 | 6,093 | 21,078 | 0.9 |
| | 584,563 | 2,419 | 586,982 | |
| **Total Costs and Return** | 656,071 | 19,273 | 675,344 | |
| **Adjustments** | | | | |
| Other Revenue | (5,375) | (219) | (5,594) | (0.0) |
| Interest on Security Deposits | 18 | - | 18 | - |
| Energy Supply Cost Variance Adjustments | 4,357 | (4,357) | - | (0.7) |
| Other | 2,388 | (8,038) | (5,650) | (1.2) |
| | 1,388 | (12,614) | (11,226) | |
| **Elasticity Adjustment** | (1,301) | 1,301 | - | 0.2 |
| **2020 Revenue Requirement from Rates** | **656,158** | **7,960** | **664,118** | 1.2 |
| **RSA** | (11,514) | 25 | (11,489) | 0.0 |
| **MTA** | 18,089 | 186 | 18,275 | 0.0 |
| **Elasticity Adjustment** | (14) | 14 | | 0.0 |
| **Billed to Customers** | **$ 662,719** | **$ 8,185** | **$ 670,904** | 1.2 |

In our review, we have addressed the major components of revenue requirement noted above, with the exception of the return on equity, and our specific comments on each are outlined in the various individual sections of this report. The appropriateness of the return on common equity will be addressed by the cost of capital experts participating in this hearing.

Previous sections of this report have reviewed the impacts on revenue requirement relating to changes in amortization of deferred regulatory accounts and depreciation.

The following section reviews forecast operating expenses. Schedule 1 of our report presents the total cost of energy to kWhs sold from 2015 to 2017 and the forecast total cost of energy to forecast kWhs for 2018, 2019 and 2020. The table and graph show that the total cost of energy per kWh increased by 3.7% from 2015 to 2017 ($0.1095 to $0.1135) and is forecast to increase by 1.1% from 2017 to proposed 2020 ($0.1135 to $0.1147). This increase is primarily attributable to the increase in depreciation, as well as the increase in the return on common equity to 9.5% included in this Application.

The effect of all of the factors noted in Newfoundland Power's Application reflect an increase in revenue requirement from rates of $6,233,000 in 2019 and $7,960,000 in 2020, which the Company is proposing to obtain by increasing rates effective March 1, 2019 by an average of 1.2%.

# Operating Expenses

Using the information presented in Schedule 1 and Schedule 2 of our report, the operating costs per customer from actual 2015 to proposed 2020 are as follows:

**Table 16: Operating Costs by Customer 2015-2020**

| | Actual 2015 | Actual 2016 | Actual 2017 | Forecast 2018F | Proposed 2019F | Proposed 2020F |
|---|---|---|---|---|---|---|
| Number of customers as at year end | 261,774 | 264,406 | 266,450 | 268,168 | 269,683 | 271,222 |
| Gross operating expenses (000's) | 88,539 | 83,563 | 83,477 | 81,024 | 78,673 | 75,279 |
| Net operating expenses (000's) | 81,512 | 75,292 | 76,954 | 75,649 | 71,759 | 72,176 |
| Gross operating expense per customer | $ 338.23 | $ 316.04 | $ 313.29 | $ 302.14 | $ 291.72 | $ 277.55 |
| Net operating expense per customer | $ 311.38 | $ 284.76 | $ 288.81 | $ 282.10 | $ 266.09 | $ 266.11 |

Based on the above information, the gross operating expense per customer decreased by 7.4% from 2015 to 2017 and is forecast to decrease by 11.4% from 2017 to proposed 2020. Net operating expense per customer decreased by 7.25% from 2015 to 2017 and is forecast to decrease by 7.86% from 2017 to proposed 2020.

Our review of operating expenses was conducted using the breakdown of expenses as outlined in Exhibit 2 of the pre-filed evidence. This exhibit provides details of the actual operating expenses for the years 2015, 2016 and 2017 as well as the forecast for 2018, 2019 and 2020.

The relationship of operating expenses to the sale of energy (expressed in kWh) is presented in Schedule 2 of our report. The table and graph show that the cost per kWh decreased from $0.0149/kWh in 2015 to $0.0140/kWh in 2016, and then increased to $0.0141/kWh in 2017. The cost per kWh was then forecast to decrease to $0.0128/kWh by 2020. This is primarily due to a decrease of gross operating expenses of $8,198,000 from 2017 to 2020. The biggest contributor to the decrease relates to employee future benefits which decreased by $9,473,000 from 2017 to 2020. Excluding employee future benefits, gross operating expenses increased by $1,275,000 (1.9%) from 2017 to 2020. Net operating expenses, excluding employee future benefits increased by $4,695,000 (7.84%) from 2017 to 2020.

Our observations and findings based on our detailed review of the individual expense categories are noted below. Where we have identified unusual trends or other concerns with forecast expenses, we have noted these in the respective sections of our report that follow.

*Operating Expenses - Key Variances*

Based upon our analytical review of Exhibit 2, "Operating Costs by Breakdown" of the Company's pre-filed evidence the following key variances between 2015 actual and 2020 forecast have been noted along with explanations provided by the Company:

- Temporary labour expense – The Company has indicated in the Application that temporary labour expense is forecast to increase in 2019 primarily as a result of increased temporary labour needed for the replacement of the Company's Customer Service System.
- Other company fees – The Company has noted that the decrease in 2017 is primarily due to a reduction in the estimated liability for third party costs associated with the investigation by the Public Utilities Board into power outages and supply issues that commenced in 2014 and are still ongoing. Further according to the Company, the forecast increases for 2018 and 2019 reflect an increased number of regulatory proceedings and external consultant costs including an assessment of the Customer Service System.
- Computing Equipment and Software – The Company has noted that increases in Computing Equipment and Software expenses are due to higher costs for third-party software licensing and support in 2018 and 2019.

**Based upon our review and analysis, nothing has come to our attention to indicate that the 2018, 2019 and 2020 forecast operating expenses are unreasonable on an overall basis.**

*Executive Compensation*

The following table provides a summary and comparison of executive compensation for forecast 2018, 2019 and 2020 with actuals for 2015, 2016 and 2017.

**Table 17: Average Compensation Per Executive 2015-2020**

| | Base Salary | Incentive (Note 1) | Other (Note 2) | Total | % Change |
|---|---|---|---|---|---|
| **Forecast 2020** | | | | | |
| Total executive group | $ 1,178,000 | $ 421,000 | $ 135,000 | $ 1,734,000 | 2.0% |
| Average per executive | $ 294,500 | $ 105,250 | $ 33,750 | $ 433,500 | 2.0% |
| **Forecast 2019** | | | | | |
| Total executive group | $ 1,155,000 | $ 413,000 | $ 132,000 | $ 1,700,000 | 1.7% |
| Average per executive | $ 288,750 | $ 103,250 | $ 33,000 | $ 425,000 | 1.7% |
| **Forecast 2018** | | | | | |
| Total executive group | $ 1,135,000 | $ 406,000 | $ 130,000 | $ 1,671,000 | -27.8% |
| Average per executive | $ 283,750 | $ 101,500 | $ 32,500 | $ 417,750 | -21.8% |
| **2017** | | | | | |
| Total executive group | $ 1,271,865 | $ 747,000 | $ 295,555 | $ 2,314,420 | 10.7% |
| Average per executive (4.33) | $ 293,733 | $ 172,517 | $ 68,258 | $ 534,508 | 2.3% |
| **2016** | | | | | |
| Total executive group | $ 1,180,144 | $ 684,000 | $ 226,663 | $ 2,090,807 | 12.6% |
| Average per executive | $ 295,036 | $ 171,000 | $ 56,666 | $ 522,702 | 12.6% |
| **2015** | | | | | |
| Total executive group | $ 1,122,000 | $ 628,000 | $ 106,244 | $ 1,856,244 | |
| Average per executive | $ 280,500 | $ 157,000 | $ 26,561 | $ 464,061 | |

Note 1: The forecast periods incentive payments reflect regulated portion only and are based on achieving 100% of target. Actual years reflect both regulated and non-regulated compensation.

Note 2: The "other" category of the annual compensation package includes items such as vehicle benefits or car allowance, insurance benefits, and self-directed RRSP employer contributions.

The Company indicated that they used Korn Ferry Hay Group Limited (the "Hay Group") to provide external expertise to assist with the review of salaries and wages for the executive and senior management employees. On January 11, 2018 the Hay Group provided a report titled "Executive Compensation – 2018 Estimated Market Actual Salary Median." The report provides an estimate of the market annual salary levels in 2018 for members of Newfoundland Power's executive team. This analysis was based upon Commercial Industrial market data in effect on May 1, 2017. The Hay Group report recommends that the Company's executive salary be compared to actual salaries paid by the Commercial Industrial executive market reference group.

The Company's current policy for executive compensation is to establish salaries based on the median of the reference group. Annual increases to executive compensation is set by the Company's Board of Directors on the basis of the information provided by the Hay Group and individual performance considerations.

In 2018, the Company's executive salary policy versus the actual base salary for executives is outlined in the table below:

**Table 18: Executive Compensation – Actual vs. Policy**

| Position | Base Salary | Salary Policy(1) | Hay Group Median(2) | Difference From Policy | Base as % of Policy |
|---|---|---|---|---|---|
| President & CEO | $ 382,000 | $ 412,600 | $ 412,600 | $ (30,600) | 93% |
| VP Customer Operations & Engineering | 295,000 | 293,600 | 305,300 | 1,400 | 100% |
| VP Finance & CFO | 234,000 | 265,600 | 254,800 | (31,600) | 88% |
| VP Regulation & Planning | 224,000 | 278,400 | 292,400 | (54,400) | 80% |
| **Total** | **$ 1,135,000** | **$ 1,250,200** | **$ 1,265,100** | **$ (115,200)** | **91%** |

(1) Provided by the Company based on advice of Hay Group effective September 1, 2018.
(2) Hay group median from letter dated January 11, 2018.

According to the Company, the base salary presented above does not correspond to the approved minutes from the meeting of the Board of Directors on January 31, 2018. The Company has noted that the approved salaries were intended for the incumbent individuals in those positions. In mid-July a reorganization was announced and several executive positions had shuffled with new individuals taking different positions.

*Salaries and Benefits*

A detailed comparison of the number of full-time equivalent ("FTE") employees for 2015 to forecast 2020 is as follows:

**Table 19: Full-time Equivalents**

| | Actual 2015 | Actual 2016 | Actual 2017 | Forecast 2018 | Forecast 2019 | Forecast 2020 |
|---|---|---|---|---|---|---|
| Permanent | 607 | 586 | 565 | 579 | 572 | 570 |
| Temporary | 46 | 49 | 46 | 40 | 52 | 53 |
| Total | 653 | 635 | 611 | 619 | 624 | 623 |
| | | | | | | |
| Managerial FTE`s | 284 | 272 | 264 | 273 | 271 | 268 |
| % managerial | 43% | 43% | 43% | 44% | 43% | 43% |
| | | | | | | |
| Union FTE`s | 323 | 313 | 301 | 306 | 301 | 303 |
| % union | 49% | 49% | 49% | 49% | 48% | 49% |

According to the Company, FTEs are determined by applying a vacancy allowance. The assumptions in determining vacancy allowances is included in the Company's report titled "*Labour Forecast 2018-2020*".

The Company's report provided detailed information concerning the methodology used to forecast test year FTEs and labour expense, as well as assumptions used to determine forecast vacancies as part of its pre-filed evidence for this GRA. In this report, Newfoundland Power states that current labour requirements tend to be consistent from year to year. The Company has noted that this is primarily due to the fact that the Company matches overall capacity and capability with anticipated work requirements when managing its workforce.

The 2018 forecast shows an increase of 8 FTE's, which primarily reflects 36 projected retirements, with all 36 of these employees to be replaced, plus an additional 11 new hires. The new hires are to meet increased requirements for engineering associated with third-party work and as well as allow for future Power Line Technician (PLT) Apprentices. According to the Company, this increase is partially offset by decreases associated with the completed deployment of automated meter reading technology. Additionally, the 2018 FTEs include employees working a partial year in 2017, but anticipated to be full time employee in 2018.

The 2019 forecast shows an increase of 5 FTE's, primarily due to the addition of 4 new PLT Apprentices and additional labour associated with the replacement of the Company's Customer Service System. Finally, the 2020 forecast reflects an overall decrease of 1 FTE, primarily due to the forecast conclusion of the Five-Year Conservation Plan: 2016-2020, partially offset by the addition of 4 new PLT Apprentices.

As part of our review we completed an analysis of the average salary per FTE, including and excluding executive compensation (base salary and STI). The results of our analysis for 2015 to forecast 2020 are included in the table below:

**Table 20: Salary Cost per Full Time Equivalent**

| | Salary Cost Per FTE | | | | | |
|---|---|---|---|---|---|---|
| | **Actual** | **Actual** | **Actual** | **Forecast** | **Forecast** | **Forecast** |
| **(000's)** | **2015** | **2016** | **2017** | **2018** | **2019** | **2020** |
| Salary costs | $63,330 | $63,608 | $64,399 | $65,430 | $66,814 | $67,932 |
| Benefit costs (net) | (7,559) | (8,470) | (8,960) | (9,117) | (9,276) | (9,462) |
| Other adjustments | (605) | (772) | (1,171) | (825) | (822) | (930) |
| Base salary costs | 55,166 | 54,366 | 54,268 | 55,488 | 56,716 | 57,540 |
| Less: executive compensation(1) | (1,750) | (1,864) | (2,016) | (1,616) | (1,644) | (1,677) |
| Base salary costs (excluding executive) | $53,416 | $52,502 | $52,252 | $53,872 | $55,072 | $55,863 |
| FTE's (including executive members) | 653 | 635 | 611 | 619 | 624 | 623 |
| FTE's (excluding executive members) | 649 | 631 | 607 | 615 | 620 | 619 |
| **Average salary per FTE** | $84.5 | $85.7 | $88.8 | $89.7 | $90.9 | $92.3 |
| **% increase** | | 1.42% | 3.63% | 0.99% | 1.33% | 1.63% |
| **Average salary per FTE (excluding executive members)** | $82.3 | $83.3 | $86.1 | $87.6 | $88.8 | $90.2 |
| **% increase** | | 1.17% | 3.39% | 1.78% | 1.34% | 1.62% |

(1) Reflects both regulated and non-regulated compensation.

In the *"Labour Forecast 2018-2020"* report, the Company has noted that the 2019 and 2020 salary increase is based on a weighted average salary increase of 1.75% and 2.00% respectively.

An analysis of salaries and wages by type of labour and by function within the Company is as follows:

**Table 21: Salary Costs by Function 2015-2020**

| (000`s) | Actual 2015 | Actual 2016 | Actual 2017 | Forecast 2018 | Forecast 2019 | Forecast 2020 |
|---|---|---|---|---|---|---|
| **Type** | | | | | | |
| Internal labour | $ 63,330 | $ 63,608 | $ 64,399 | $ 65,430 | $ 66,814 | $ 67,932 |
| Overtime | 5,117 | 4,925 | 6,807 | 5,616 | 5,715 | 5,829 |
| | 68,447 | 68,533 | 71,206 | 71,046 | 72,529 | 73,761 |
| Contractors | 15,232 | 10,593 | 12,883 | 12,903 | 13,128 | 13,391 |
| Total | $ 83,679 | $ 79,126 | $ 84,089 | $ 83,949 | $ 85,657 | $ 87,152 |
| **Function** | | | | | | |
| Operating (1) | $ 36,485 | $ 36,770 | $ 39,341 | $ 38,577 | $ 39,513 | $ 39,899 |
| Capital miscellaneous | 47,194 | 42,356 | 44,748 | 45,372 | 46,144 | 47,253 |
| Total | $ 83,679 | $ 79,126 | $ 84,089 | $ 83,949 | $ 85,657 | $ 87,152 |

(1) The operating labour figures provided in Exhibit 2 for 2015 to 2020 forecast exclude non-regulated expenses, CDM program labour and OPEB current service costs. A reconciliation between above table for operating and Exhibt 2 as provided by the Company is as follows:

| | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 |
|---|---|---|---|---|---|---|
| Operating Labour, Exhibit 2 | **$ 33,941** | **$ 33,760** | **$ 35,739** | **$ 35,124** | **$ 36,316** | **$ 36,772** |
| Non-regulated labour | 697 | 931 | 1,184 | 1,040 | 734 | 842 |
| CDM Program Labour | 879 | 1,098 | 1,238 | 1,288 | 1,287 | 1,056 |
| OPEB current service costs | 968 | 981 | 1,180 | 1,125 | 1,176 | 1,229 |
| Operating Labour, above | **$ 36,485** | **$ 36,770** | **$ 39,341** | **$ 38,577** | **$ 39,513** | **$ 39,899** |

Our review of salaries and benefits included an analysis of the year-to-year variance, consideration of the trends in labour costs and investigation of significant variances.

### *Short-Term Incentive ("STI") Program*

Newfoundland Power's Executives and Directors participate in the Company's Short-Term Incentive ("STI") program. The Company has indicated that the underlying rationale for the STI program is to incent senior management performance by making a significant portion of total compensation dependent on performance.

The Company currently monitors several corporate performance measures. In response to Requests for Information PUB-NP-010, the Company has provided the following description of the performance measures:

- **Controllable Operating Cost per Customer**: This measure is based on budgeted controllable operating expenses. The Company has noted that because costs such as intercompany charges, PUB assessments, severances and regulatory amortizations are beyond the short-term control of management they are excluded from the target.

- **Earnings:** This measure represents corporate earnings as per the year-end audited financial statements. The target is based on the Company's earnings budgeted for the year.

- **Duration of Outages (SAIDI):** This measure represents the reliability of the power system in terms of the duration of outages experienced by customers.

- **Customer Satisfaction:** This measure represents Newfoundland Power's customer satisfaction rating which is obtained through independently conducted quarterly surveys of customers with respect to the Company's service.

- **Regulatory Performance:** This measure is dependent on regulatory activity for the year. The quality, timeliness and effectiveness of the regulatory filings are included in the assessment of regulatory performance.

- **Safety (All Injury Frequency Rate):** This measure is the number of preventable injuries per 200,000 hours of work and is a combination of both the number of preventable medical aid and lost time injuries.

The following table outlines the actual results for corporate performance for 2015, 2016 and 2017 and targets for 2018:

**Table 22: Short-Term Incentive Targets 2015-2018**

| Measure | Actual 2015 | Actual 2016 | Actual 2017 | Forecast 2018 |
|---|---|---|---|---|
| Controllable Operating Cost per Customer | $ 219.8 | $ 219.7 | $ 228.8 | $ 222.0 |
| Earnings | 38.8m | 40.0m | 41.0m | 40.0m |
| Duration of Outages (SAIDI) | 2.36 | 2.24 | 2.28 | 2.27 |
| Customer Satisfaction | 86.10% | 86.10% | 86.50% | 86.50% |
| Regulatory Performance | 140% | 140% | 120% | Subjective |
| Safety (All Injury Frequency Rate) | 0.18 | 0.40 | 0.18 | 0.18 |

Note 1: The Company has indicated that targets for 2019 and 2020 have not been finalized and approved by the Board of Directors at the time of this report.

The forecast STI payment includes assumptions regarding the corporate performance as outlined in the table above. The Company forecast performance is based upon achieving 100% of targets.

The Company's STI program also includes an individual performance measure for Executives and Directors. This measure is used to reinforce the accountability and achievement of individual performance targets.

The weight between corporate performance and individual performance differs between the managerial classifications, as outlined in the following table:

**Table 23: Short-Term Incentive Performance Weightings**

| Classification | Corporate Performance | Individual Performance |
|---|---|---|
| President and CEO | 70% | 30% |
| Vice-Presidents | 50% | 50% |
| Directors | 50% | 50% |

According to the Company, the individual measures are aligned with the specific focus of the executive or director, and are designed to promote leadership in enhancing employee and corporate performance in specific areas of responsibility. Individual measures and weightings are adjusted annually to reflect corporate priorities. The program operates to provide 100% payout of established STI pay if the Company meets, on average, 100% of its performance targets. For 2017, measures relating to 'Earnings', 'SAIDI', 'Customer Satisfaction', 'Safety', and 'Regulatory Performance' metrics were met, however, 'Controllable Operating Costs/Customer' metric fell below target.

The following table illustrates the target as a percentage of base pay, together with the actual STI payouts for 2015, 2016 and 2017, as well as for forecast results for 2018, 2019 and 2020:

**Table 24: Short Term Incentive Payout as a Percent of Base Pay 2015-2020**

| | STI Payout | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | Target 2015 | Actual 2015 | Target 2016 | Actual 2016 | Target 2017 | Actual 2017 | Target 2018 | Target 2019 | Target 2020 |
| President | 50% | 65% | 50% | 67% | 50% | 66% | 50% | 42% | 42% |
| Vice-Presidents | 40% | 52% | 40% | 54% | 40% | 57% | 35-40% | 42% | 42% |
| Directors | 15% | 20% | 15% | 20% | 15% | 20% | 15% | 15% | 15% |

In dollar terms, the actual STI payouts for 2015, 2016 and 2017 and forecast payouts for 2018, 2019, and 2020 are summarized in the below table:

**Table 25: Short Term Incentive Payout by Category 2015-2020**

| | Actual 2015 | Actual 2016(1) | Actual 2017 | Forecast 2018 | Forecast 2019(2) | Forecast 2020(2) |
|---|---|---|---|---|---|---|
| President | $ 227,000 | $ 242,000 | $ 240,396 | $ 191,000 | $ 194,343 | $ 198,229 |
| Vice-Presidents | 401,000 | 442,000 | 506,604 | 289,500 | 294,566 | 300,458 |
| Directors | 342,200 | 312,122 | 332,999 | 243,105 | 247,359 | 252,307 |
| Sub-total | $ 970,200 | $ 996,122 | $ 1,079,999 | $ 723,605 | $ 736,268 | $ 750,993 |
| Less: Non-regulated portion | (224,170) | (367,818) | (301,080) | (99,000) | (101,000) | (103,000) |
| Total Regulated | $ 746,030 | $ 628,304 | $ 778,919 | $ 624,605 | $ 635,268 | $ 647,993 |

(1): The 2016 figures are $11,178 less than what the Company provided during our 2016 annual review. The difference is related to the directors compensation.

(2): 2019 and 2020 forecast amounts were inflated by 1.75% and 2.00% respectively.

In accordance with Order No.'s P.U. 19 (2003) and P.U. 18 (2016) the Company has both classified STI payouts in excess of 100% of target and 50% of STI payouts related to earnings and regulatory performance components as a non-regulated expense. In the response to PUB-NP-010, the Company has stated that 2018, 2019 and 2020 forecast of the STI payouts are based on achieving 100% of targets, as such, only the non-regulated portion related to the earnings and regulatory performance are included in the above payouts.

*Employee Future Benefits*

The Company maintains plans for its employees which provide for benefits upon retirement. The Company has grouped these into two broad categories: pension plans and other post-employment benefits (OPEBs) plans.

The components of employee future benefits expense are as follows:

**Table 26: Employee Future Benefit Breakdown 2015-2020**

| (000's) | Actual 2015 | Actual 2016 | Actual 2017 | Forecast 2018 | Forecast 2019 | Forecast 2020 |
|---|---|---|---|---|---|---|
| Pension Expense | $17,702 | $9,763 | $8,675 | $7,835 | $2,882 | $1,263 |
| OPEBs Expense | 8,653 | 8,678 | 8,364 | 6,194 | 6,198 | 6,303 |
| | $26,355 | $18,441 | $17,039 | $14,029 | $9,080 | $7,566 |

Company Pension Plan

For 2018, 2019 and 2020, we reviewed the estimates supporting the forecast gross charge for pension expense of $7,835,000, $2,882,000 and $1,263,000 respectively. The 2018 pension expense is forecast to decrease by $840,000 from 2017 with further decreases forecast for 2019 and 2020 of $4,953,000 and $1,619,000, respectively.

The components of pension expense are as follows:

**Table 27: Pension Expense Breakdown – 2015-2020**

| (000's) | Actual 2015 | Actual 2016 | Actual 2017 | Forecast 2018 | Forecast 2019 | Forecast 2020 |
|---|---|---|---|---|---|---|
| Pension Expense per Actuary | $15,332 | $7,330 | $6,165 | $5,162 | ($145) | ($1,988) |
| PUP/SERP[1] | 562 | 557 | 571 | 521 | 515 | 546 |
| Group and Individual RRSPs | 1,805 | 1,881 | 1,961 | 2,172 | 2,532 | 2,725 |
| Less: Offset | 3 | (5) | (22) | (20) | (20) | (20) |
| Total Pension Expense | **$17,702** | **$9,763** | **$8,675** | **$7,835** | **$2,882** | **$1,263** |
| | | | -11% | -10% | -63% | -56% |

Note 1: Pension uniformity plan (PUP); Supplemental employee retirement program (SERP).

Pension expense is expected to decrease by approximately $16,439,000 between 2015 and 2020, with approximately $7,939,000 of this decrease taking place from 2015 to 2016. This decrease was primarily caused by a higher discount rate at December 31, 2015, which is used to determine the pension obligation in 2016, and an expected higher service life of active members. A decline is expected to continue into 2020, and according to the Company, is influenced by a combination of factors including; increase in plan assets due to increased solvency payments to 2015, return on plan assets to 2017, the expiry of regulatory amortizations in 2017, a stable forecast discount rate, and the results of the Company's defined benefit pension plan valuation dated December 31, 2017. We have compared forecast expense for 2018-2020 to support provided by the Company's actuaries and have found no discrepancies.

The Company's pension uniformity plan is meant to eliminate the inequity in the regular pension plan related to the limitation on the maximum level of contributions permitted by income tax legislation. In effect, the pension uniformity plan tops up the benefits for senior management so that they receive benefits equivalent to the benefit formula of the registered pension plan. The Board ordered in Order No. P.U. 7 (1996-97) that the pension uniformity plan be allowed as reasonable, prudent, and properly chargeable to the operating account of the Company.

As a result of the closure of the Defined Benefit Pension Plan, all new employees are required to participate in the Defined Contribution Plan (Individual RRSPs). The employer's portion of the contributions to the Group RRSP is calculated as 1.5% of the base salary paid to the plan participants. Individual RRSPs will increase year over year with the number of new hires at the Company. The increase in Group and Individual RRSPs from 2015 to 2020F is due to wage increases and new hires. Group and Individual RRSPs are forecast by the Company using an estimated compensation increase factor of approximately 3.50% for 2018, 2019 and 2020 forecast.

Other Post-Employment Benefits (OPEBs)

In its 2010 General Rate Application, the Company proposed the implementation of the accrual method of accounting for OPEBs expenses. The proposal included a deferral mechanism to capture annual variances arising from changes in the discount rate and other assumptions, and recommendations related to the recovery of the transitional balance associated with the adoption of accrual accounting for OPEBs costs. In Order No. P.U. 31 (2010) the Board decided the Company should use the accrual method of accounting for OPEBs costs and income tax related to OPEBs as of January 1, 2011.

The Board also required that the transitional balance for OPEBs expense be amortized using the straight-line method over a period of 15 years. The Board also approved the creation of the OPEBs Cost Variance Deferral Account to limit the variability of the OPEBs costs due to changing assumptions such as discount rates.

The components of OPEBs expense for 2015, 2016 and 2017, and forecast for 2018, 2019 and 2020 are as follows:

**Table 28: Other Post-Employment Benefits Breakdown 2015-2020**

| (000's) | Actual 2015 | Actual 2016 | Actual 2017 | Forecast 2018 | Forecast 2019 | Forecast 2020 |
|---|---|---|---|---|---|---|
| OPEBs Accrual | $6,055 | $6,089 | $5,861 | $3,649 | $3,696 | $3,846 |
| Amortization of Transitional Amounts | 3,504 | 3,504 | 3,504 | 3,504 | 3,504 | 3,504 |
| Less: Amount Capitalized | (906) | (915) | (1,001) | (959) | (1,002) | (1,047) |
| Total OPEBs Expense | $8,653 | $8,678 | $8,364 | $6,194 | $6,198 | $6,303 |

The discount rate used to prepare the 2018, 2019 and 2020 forecast was 3.60%, which represents a decrease of 0.30% from 2017. These rates are consistent with those used to prepare the pension forecast above. We have compared forecast expense for 2018-2020 to support provided by the Company's actuaries and have found no discrepancies.

### *Finance Charges*

Our procedures with respect to interest on long term debt and other interest included a recalculation of interest charges and assessment of reasonableness based on debt outstanding.

The following table summarizes the various components of finance charges:

**Table 29: Finance Charges 2015-2020**

| (000's) | Actual 2015 | Actual 2016 | Actual 2017 | Forecast 2018 | Proposed 2019 | Proposed 2020 |
|---|---|---|---|---|---|---|
| Interest | | | | | | |
| Long-term Debt | $ 35,020 | $ 34,846 | $ 35,013 | $ 35,789 | $ 35,374 | $ 37,080 |
| Other | 1,139 | 878 | 672 | 732 | 1,679 | 1,213 |
| Amortization | | | | | | |
| Debt Issue Expense | 242 | 223 | 234 | 232 | 224 | 219 |
| Debt Portion of AFUDC | (677) | (712) | (554) | (444) | (470) | (485) |
| Equity Portion of AFUDC | (563) | (592) | (471) | (541) | (575) | (585) |
| Total Finance Charges - Exhibit 5 | **$35,161** | **$34,643** | **$34,894** | 35,768 | 36,232 | 37,442 |
| Less: Interest on Security Deposits | | | | (16) | (18) | (18) |
| Total Finance Charges - Return on Rate Base | | | | **$35,752** | **$ 36,214** | **$ 37,424** |
| Year over year percentage change | | | | 2.46% | 1.29% | 3.34% |

Forecast finance charges proposed for 2019 are expected to increase from 2018 by 1.29% resulting primarily from an increase in credit facility costs. The proposed forecast for 2020 also increased over the previous forecast year due to the expected issuance of debt on April 15, 2020 of $74,250,000 partially offset by the October 1, 2020 redemption of $30,000,000. The April 2020 issuance is expected to have a 5.25% rate whereas the October 2020 redeemed loan carries a 9% rate.

The Company has the forecast average short-term borrowing rate to be 2.60% for 2018, 3.27% for 2019, and 3.60% for 2020. We have reviewed the short-term interest rates included in the Company's assumptions and they are consistent with interest rate forecast from the five major banks in Canada.

**Based upon our analysis, nothing has come to our attention to indicate that the forecast finance charges for 2018 and the proposed finance charges for 2019 and 2020 are unreasonable.**

### *Income Tax Expense*

Our review of income tax expense included a recalculation of income taxes based on substantively enacted corporate income tax rates for Federal and Provincial jurisdictions and an assessment of reasonableness based on forecast income and substantively enacted rates for 2015, 2016 and 2017 actuals, the 2018 forecast and proposed forecast for 2019 and 2020.

**Table 30: Income Tax Expense 2015-2020**

| | Actual 2015 | Actual 2016 | Actual 2017 | Forecast 2018 | Forecast 2019 | Forecast 2020 | Proposed 2019 | Proposed 2020 |
|---|---|---|---|---|---|---|---|---|
| Income Before Tax (000's) | $ 57,642 | $ 61,039 | $ 63,412 | $ 60,554 | $ 52,437 | $ 49,478 | $ 69,471 | $ 72,016 |
| Income Taxes (000's) | $ 16,529 | $ 18,152 | $ 19,424 | $ 18,137 | $ 15,814 | $ 14,985 | $ 20,320 | $ 21,078 |
| Effective Income Tax Rate (%) | 28.68% | 29.74% | 30.63% | 29.95% | 30.16% | 30.29% | 29.25% | 29.27% |
| Statutory Income Tax Rate (%) | 29.00% | 30.00% | 30.00% | 30.00% | 30.00% | 30.00% | 30.00% | 30.00% |

The income tax figure presented above is after adjustment for non-regulated expenses.

The Company's effective income tax rate is comparable to the statutory income tax rate in effect at the time of the Application for both the existing and proposed forecast.

**Based upon our analysis, income tax expense for forecast 2018 and proposed 2019 and 2020 appear consistent with substantively enacted corporate income tax rates and forecast increases in net income.**

### *Intercompany Charges*

Our review of Intercompany Charges included the following specific procedures:

- assessed the Company's compliance with Order No.'s P.U. 19 (2003), P.U 32 (2007) and P.U. 3 (2009); and,
- compared charges for 2018, 2019 and 2020 forecast to previous years and obtained explanations for unusual fluctuations and trends.

As part of the 2017 annual review, we reviewed Fortis Inc.'s methodology to estimate its recoverable expenses over the first three quarters as well as its "true up" calculation for the 4th Quarter. We noted during our review that Fortis Inc. continues to allocate its recoverable costs based on its subsidiaries' assets. There were no changes to the methodology in 2017.

- Fortis Inc. estimated its net pool of operating expenses for 2017 based on the 2018-2022 business plan and determined its estimated billings based on the pro-rata portion of such net costs using the estimated assets of subsidiaries. For Quarters 1 through 3 Fortis Inc. billed based upon the estimated annual amount.
- For the fourth quarter, a true-up calculation is completed to reflect actual expenses incurred during the year.

The following table provides a breakdown of inter-corporate charges from affiliates for 2015, 2016 and 2017, including forecast charges for 2018, 2019 and 2020:

**Table 31: Charges from Affiliates including Fortis Inc. 2015-2020F**

| Intercompany transactions | Actual 2015 | Actual 2016 | Actual 2017 | Forecast 2018 | Forecast 2019 | Forecast 2020 |
|---|---|---|---|---|---|---|
| **Charges from Affiliates including Fortis Inc.** | | | | | | |
| Trustee & Shareplan Costs | $ 35,000 | $ 33,000 | $ 26,000 | $ 27,000 | $ 27,000 | $ 28,000 |
| Hotel/Banquet Facilities | 3,000 | - | - | - | - | - |
| Staff Charges | 20,000 | - | - | - | - | - |
| Miscellaneous | 151,000 | 121,000 | 199,000 | 973,000 | 121,000 | 124,000 |
| **Total** | **$ 209,000** | **$ 154,000** | **$ 225,000** | **$ 1,000,000** | **$ 148,000** | **$ 152,000** |
| Year over year percentage change | | -26% | 46% | 344% | -85% | 3% |

The most significant observations from our analysis of charges to affiliated companies from 2015 to 2020 are as follows:

- Miscellaneous chargers were higher in 2017 as a result of a lump sum Supplemental Employee Retirement Plan ("SERP") payment of $45,577. Forecast costs in 2018 include a lump sum SERP payment of $817,117.

The following table provides a breakdown of inter-corporate charges to affiliates for 2015, 2016 and 2017, including forecast charges for 2018, 2019 and 2020:

**Table 32: Charges to Affiliates including Fortis Inc. 2015-2020F**

| Intercompany transactions | Actual 2015 | Actual 2016 | Actual 2017 | Forecast 2018 | Forecast 2019 | Forecast 2020 |
|---|---|---|---|---|---|---|
| **Charges to Affiliates including Fortis Inc.** | | | | | | |
| Printing & Stationary | $ 2,000 | $ - | $ - | $ - | $ - | $ - |
| Postage | 19,000 | 8,000 | 4,000 | 3,000 | 3,000 | 3,000 |
| Staff Charges | 136,000 | 279,000 | 1,013,000 | 473,000 | 210,000 | 210,000 |
| Staff Charges - Insurance | 31,000 | 6,000 | - | - | - | - |
| IS Charges | 18,000 | - | 6,000 | 5,000 | 5,000 | 5,000 |
| Miscellaneous | 23,000 | 36,000 | 1,184,000 | 145,000 | 42,000 | 43,000 |
| **Total** | **$ 229,000** | **$ 329,000** | **$ 2,207,000** | **$ 626,000** | **$ 260,000** | **$ 261,000** |
| Year over year percentage change | | 44% | 571% | -72% | -58% | 0% |

The most significant observations from our analysis of charges to affiliated companies from 2015 to 2020 are as follows:

- Staff Charges are higher in 2017 as a result of hurricane relief efforts in Turks & Caicos after Hurricane Irma. Forecast costs in 2018 include labour charge to Fortis Ontario.
- Miscellaneous charges to Fortis show a significant increase in 2017. According to the Company, this relates to the relief effort in Turks & Caicos after hurricane Irma in 2017 and partially into 2018.

**Based upon our analysis, intercompany charges are calculated using a methodology that is consistent year over year. As a result of our review, nothing has come to our attention that would lead us to believe that forecast intercompany charges are unreasonable.**

*Purchased Power*

We have reviewed the Company's purchased power expense forecast for 2018, 2019 and 2020 and have investigated the reasons for any fluctuations and changes. We recalculated the cost per kilowatt-hour charged by Newfoundland and Labrador Hydro and found purchased power charges to be consistent with the established rates provided. Forecast purchase power expense reflects the utility rate effective on July 1, 2017 approved in order No. P.U. 22 (2017). The purchased power cost do not reflect the July 1, 2018 utility rate approved in order No. P.U. 15 (2018).

**Table 33: Purchased Power 2015-2020**

| (000's) | Actual 2015 | Actual 2016 | Actual 2017 | Existing 2018 | Existing 2019 | Existing 2020 |
|---|---|---|---|---|---|---|
| Purchases From Hydro | $ 424,430 | $ 443,311 | $ 435,306 | $ 432,443 | $ 430,627 | $ 430,644 |
| Amortization of WNR | (2,335) | - | - | - | - | - |
| DMI | - | - | (2,128) | - | - | - |
| Wholesale rate change flow-through | - | - | 7,071 | - | - | - |
| | $ 422,095 | $ 443,311 | $ 440,249 | $ 432,443 | $ 430,627 | $ 430,644 |
| Year Over Year % Change | | 5.03% | -0.69% | -1.77% | -0.42% | 0.00% |

| | Actual 2015 | Actual 2016 | Actual 2017 | Proposed 2018 | Proposed 2019 | Proposed 2020 |
|---|---|---|---|---|---|---|
| Purchases from Hydro | $ 424,430 | $ 443,311 | $ 435,306 | $ 432,443 | $ 429,949 | $ 429,144 |
| Amortization of WNR | (2,335) | - | - | - | - | - |
| DMI | - | - | (2,128) | - | - | - |
| Wholesale rate change flow-through | - | - | 7,071 | - | - | - |
| | $ 422,095 | $ 443,311 | $ 440,249 | $ 432,443 | $ 429,949 | $ 429,144 |
| Year Over Year % Change | | 5.03% | -0.69% | -1.77% | -0.58% | -0.19% |

Purchase power expense is expected to increase over 2015 to 2020 due to an increase in Hydro's Utility Rate effective July 1, 2017 partially offset by declining energy sales. According to the Company, the forecast decrease is consistent with the recent decline in the provincial economy, which is attributable to a number of factors, including lower commodity process, reduced shellfish processing and reduced construction activity related to major projects.

**Based upon our analysis, purchased power forecast for 2018, 2019 and 2020 appears consistent with billing rates from Newfoundland and Labrador Hydro using the effective July 1, 2017 and forecast decrease in energy sales.**

# Non-Regulated Expenses

Our review of non-regulated expenses included the following procedures:

- assess the Company's compliance with Board Orders;
- compared non-regulated expenses for the 2018, 2019 and 2020 forecast to prior years and investigated any unusual fluctuations.

**Table 34: Non-regulated Expenses 2015-2020**

| Non-regulated expenses ('000) | Actual 2015 | Actual 2016 | Actual 2017 | Forecast 2018 | Forecast 2019 | Forecast 2020 |
|---|---|---|---|---|---|---|
| Labour Costs | $ 696 | $ 931 | $ 1,184 | $ 1,040 | $ 734 | $ 842 |
| Intercompany Charges | 1,525 | 2,114 | 1,988 | 1,873 | 1,962 | 1,966 |
| Community Relations and Other | 299 | 341 | 334 | 342 | 348 | 355 |
| Corporate Advertising | 14 | 12 | 11 | 11 | 11 | 11 |
| Non-regulated Expenses Before Tax | 2,534 | 3,398 | 3,517 | 3,266 | 3,055 | 3,174 |
| Less: Income Taxes | 735 | 1,019 | 1,055 | 980 | 917 | 952 |
| Non-regulated Expenses After Tax | $ 1,799 | $ 2,379 | $ 2,462 | $ 2,286 | $ 2,138 | $ 2,222 |

The 2018, 2019 and 2020 non-regulated expenses have been forecast at $3,266,000, $3,055,000 and $3,174,000 (before tax) respectively, as compared to $3,517,000 in 2017.

In compliance with Order No. P.U. 19 (2003) the Company has classified short term incentive payouts in excess of 100% of target payouts as non-regulated expense. For 2019 and 2020, the Company has estimated that performance will be at 100% of targets and therefore the expectation is that the STI payout will not exceed 100%. The Company is also in compliance with Order No. P.U. 18 (2016), as 50% of short term incentive payouts related to earnings and regulatory performance components have also been classified as non-regulated expenses. Details on the short term incentive payouts are included in this report under the heading STI Program.

**Based upon our review and analysis, nothing has come to our attention to indicate that the amounts reported as non-regulated expenses, as summarized above, are unreasonable or not in accordance with Board Orders.**

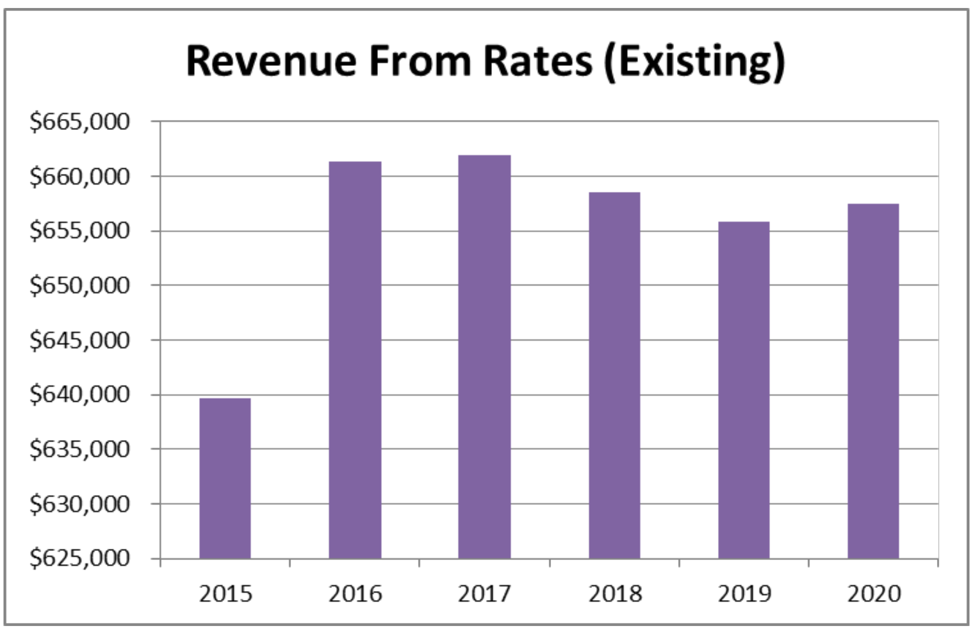
# Proposed Forecast Revenue

## Revenue from Rates

We have compared the actual revenues for 2015, 2016 and 2017 to the forecast revenues using existing rates for 2018 to 2020 to assess any significant trends. The Company has indicated in its Application that the revenue forecast is based on the "Customers, Energy and Demand Forecast" dated April 2018. The results of this analysis by rate class are as follows:

**Table 35: Existing Revenue from Rates 2015-2020F**

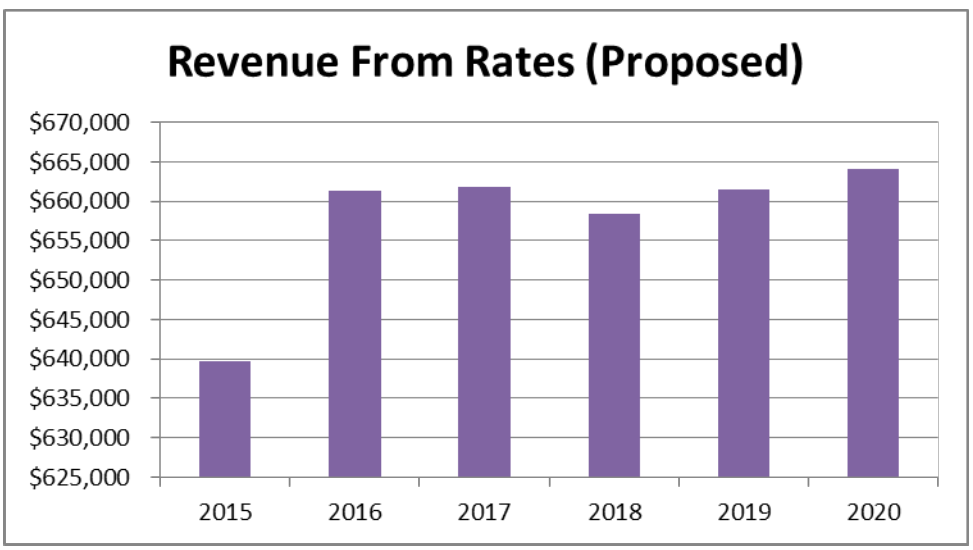
| (000's) | Actual 2015 | Actual 2016 | Actual 2017 | Forecast 2018 | Forecast 2019 | Forecast 2020 |
|---|---|---|---|---|---|---|
| Residential | $ 403,910 | $ 420,159 | $ 422,237 | $ 419,559 | $ 414,670 | $ 414,545 |
| General Service | | | | | | |
| 0-100 kw | 85,093 | 88,362 | 88,507 | 88,450 | 88,603 | 89,354 |
| 110-1000 kva | 93,725 | 96,404 | 95,565 | 96,413 | 97,103 | 97,693 |
| Over 1000 kva | 38,400 | 38,021 | 37,099 | 35,340 | 36,803 | 37,130 |
| Streetlighting | 15,541 | 15,928 | 16,149 | 16,169 | 16,236 | 16,306 |
| Discounts Forfeited | 2,962 | 2,507 | 2,327 | 2,535 | 2,426 | 2,431 |
| Revenue From Rates | $ 639,631 | $ 661,381 | $ 661,884 | $ 658,466 | $ 655,841 | $ 657,459 |
| Year over year % change | | 3.40% | 0.08% | -0.52% | -0.40% | 0.25% |



The table below summarizes the actual revenues for 2015, 2016 and 2017 to the forecast revenues using proposed rates for 2019 to 2020 to assess any significant trends:

**Table 36: Proposed Revenue from Rates 2015-2020P**

| (000's) | Actual 2015 | Actual 2016 | Actual 2017 | Forecast 2018 | Proposed 2019 | Proposed 2020 |
|---|---|---|---|---|---|---|
| Residential | $ 403,910 | $ 420,159 | $ 422,237 | $ 419,559 | $ 417,996 | $ 418,374 |
| General Service | | | | | | |
| 0-100 kw | 85,093 | 88,362 | 88,507 | 88,450 | 89,367 | 90,333 |
| 110-1000 kva | 93,725 | 96,404 | 95,565 | 96,413 | 98,039 | 98,877 |
| Over 1000 kva | 38,400 | 38,021 | 37,099 | 35,340 | 37,178 | 37,578 |
| Streetlighting | 15,541 | 15,928 | 16,149 | 16,169 | 16,441 | 16,503 |
| Discounts Forfeited | 2,962 | 2,507 | 2,327 | 2,535 | 2,446 | 2,453 |
| Revenue From Rates | $ 639,631 | $ 661,381 | $ 661,884 | $ 658,466 | $ 661,467 | $ 664,118 |
| Year over year % change | | 3.40% | 0.08% | -0.52% | 0.46% | 0.40% |




The Company's revenues have been fluctuating by various percentages since 2015. The Company has noted the following reasons for the changes in the revenue levels from 2015 to 2020:

- The 3.4% increase in 2016 over 2015 was primarily due to increases in customer energy rates. Rates increased on July 1, 2015 and July 1, 2016 as a result of the Board's approval of the electricity rate charged from Newfoundland and Labrador Hydro to the Company in 2015 and approval of the rate increase as a result of the 2016/2017 GRA.
- The 2019 forecast decrease in revenues using existing rates in effect is 0.4% under the 2018 forecast. Under the new rates proposed in this Application, the revenues for 2019 are forecast to increase 0.46% over 2018 forecast, which is primarily a result of the proposed rate increase of 1.2%.

- The 2020 forecast increase in revenues using existing rates in effect is 0.25% over the 2019 forecast. Under the new rates proposed in this Application, the increase in revenues for 2020 over proposed 2019 is 0.4%, which is primarily a result of the proposed rate increase of 1.2% being enacted the entire twelve months. The proposed rates would take effect March 1, 2019.

The number of customers and the GWhs sold to these customers for 2015 to 2017 and forecast 2018 to 2020 and proposed 2019 and 2020 are as follows:

**Table 37: Customers and Electricity Sold 2015-2020**

| | Actual 2015 | Actual 2016 | Actual 2017 | Forecast 2018 | Forecast 2019 | Forecast 2020 |
|---|---|---|---|---|---|---|
| Customers | 261,774 | 264,406 | 266,450 | 268,168 | 269,683 | 271,222 |
| % Change | | 1.01% | 0.77% | 0.64% | 0.56% | 0.57% |
| GWh Sold | 5,957 | 5,950 | 5,922 | 5,915 | 5,889 | 5,899 |
| % Change | | -0.12% | -0.47% | -0.12% | -0.44% | 0.17% |

| | Actual 2015 | Actual 2016 | Actual 2017 | Forecast 2018 | Proposed 2019 | Proposed 2020 |
|---|---|---|---|---|---|---|
| Customers | 261,774 | 264,406 | 266,450 | 268,168 | 269,683 | 271,222 |
| % Change | | 1.01% | 0.77% | 0.64% | 0.56% | 0.57% |
| GWh Sold | 5,957 | 5,950 | 5,922 | 5,915 | 5,883 | 5,887 |
| % Change | | -0.12% | -0.47% | -0.12% | -0.54% | 0.07% |

Source: Tables 1-1 and 5-3 of pre-filed evidence.

As the above table indicates, from 2015 to 2016 the number of customers increased by 1.01%, and from 2016 to 2017 the number of customers increased again by 0.77%. This trend is forecasted to continue to increase for 2018 to 2020 forecast with an annual increase of 0.64%, 0.56%, and 0.57%, respectively.

GWhs sold decreased by 0.12% from 2015 to 2016, and again by 0.47% from 2016 to 2017. Under existing rates, the Company has forecast a decline in GWhs sold of 0.12% and 0.44% for 2018 and 2019, respectively, followed by an increase of 0.17% for 2020. According to the Company, the forecast increase in 2020 can be primarily attributed to the extra day provided as a result of 2020 being a leap year, and without the additional day, GWhs sold would have been forecast to decrease to 5,883 GWhs, or by 0.1%. The decrease in GWhs sold from existing to proposed forecast is related to the elasticity effects of the proposed rate increase.

Although the number of customers is expected to increase by an average of 0.7% per year over the 2015 to 2020 year period, GWHs sold is expected to decrease primarily as a result of an expected decrease in domestic average use. According to the Company, the decline in domestic average use reflects the forecast increase in the price of electricity, the decline in household disposable income, as well the impact of conversation and demand management programs. The Conference Board of Canada projects an average decrease in disposable income of 1.8% from 2018 to 2020.

In reviewing the 2018 to 2020 forecast revenues, we agreed all forecast amounts to supporting schedules provided by the Company. In addition, we calculated the average revenue forecast per customer by rate class to assess its reasonableness.

**Based on our procedures nothing has come to our attention to indicate the forecast revenues from rates for 2018, 2019 and 2020 appear unreasonable.**

**Other Revenue**

The Company's other revenue for 2015, 2016, and 2017 and forecast for 2018, 2019, and 2020 is as follows:

**Table 38: Other Revenue 2015-2020**

| ($000s) | Actual 2015 | Actual 2016 | Actual 2017 | Forecast 2018 | Forecast 2019 | Forecast 2020 |
|---|---|---|---|---|---|---|
| Pole Attachment | $ 1,744 | $ 1,902 | $ 2,429 | $ 2,299 | $ 2,318 | $ 2,360 |
| Provisioning Work | 707 | 737 | 931 | 1,227 | 943 | 883 |
| Customer account interest | 977 | 923 | 888 | 929 | 913 | 909 |
| Interest on RSA | 63 | 281 | 615 | 373 | (28) | (219) |
| Wheeling Charges | 654 | 699 | 714 | 745 | 751 | 758 |
| Miscellaneous | 1,061 | 692 | 706 | 807 | 687 | 684 |
| **Total** | **$ 5,206** | **$ 5,234** | **$ 6,283** | **$ 6,380** | **$ 5,584** | **$ 5,375** |
| Year to year % change | | 0.54% | 20.04% | 1.54% | (12.48%) | (3.74%) |

| ($000s) | Actual 2015 | Actual 2016 | Actual 2017 | Forecast 2018 | Proposed 2019 | Proposed 2020 |
|---|---|---|---|---|---|---|
| Pole Attachment | $ 1,744 | $ 1,902 | $ 2,429 | $ 2,299 | $ 2,318 | $ 2,360 |
| Provisioning Work | 707 | 737 | 931 | 1,227 | 943 | 883 |
| Customer account interest | 977 | 923 | 888 | 929 | 913 | 909 |
| Interest on RSA | 63 | 281 | 615 | 373 | - | - |
| Wheeling Charges | 654 | 699 | 714 | 745 | 751 | 758 |
| Miscellaneous | 1,061 | 692 | 706 | 807 | 687 | 684 |
| **Total** | **$ 5,206** | **$ 5,234** | **$ 6,283** | **$ 6,380** | **$ 5,612** | **$ 5,594** |
| Year to year % change | | 0.54% | 20.04% | 1.54% | (12.04%) | (0.32%) |

The tables above indicate the following variances:

- Pole attachment – Revenue related to pole attachments was higher in 2017 as a result of higher pole attachment rates charged to cable TV operators and increased pole attachments attributable to network upgrade initiatives.
- Provisioning work - The Company has indicated that provisioning work forecast for 2019 and 2020 shows a decline from the 2018 forecast as a result of network upgrade initiatives forecasted to be undertaken by telecommunications providers in 2018.
- Interest on RSA – Interest increased 2015 through to 2017 as a result of the transfer of the 2015 year-end balance in the weather normalization account and impacts of the July 1, 2017 wholesale rate flow through. Forecast interest for 2018 is expected to drop as a result of a transfer into the RSA related to the July 1, 2017 wholesale rate flow through. Further drop in interest in 2019 and 2020 is primarily due to the forecast transfers for PEVDA and OPEVDA, which serves to reduce the balance in the RSA and associated interest.

- Miscellaneous – Miscellaneous revenue is forecasted to increase in 2018 as there are major initiatives by telecommunication companies to upgrade their respective network creating more scheduled work. The majority of this work is expected to be completed in 2018 and miscellaneous revenue is forecast to drop back in 2019.

**Based on our procedure nothing has come to our attention to indicate the forecast other revenues for 2018, 2019 and 2020 appear unreasonable.**

## Proposed Revenue from Rates

The Company is proposing that the Board approve rates, tolls and charges effective for service provided on and after March 1, 2019, to provide an average increase by class in electrical rates of 1.2%, based upon:

a) a forecast average rate base for 2019 of $1,146,293,000 and for 2020 of $1,179,357,000;
b) a rate of return on average rate base for 2019 of 7.47% in the range of 7.29% to 7.65% and for 2020 of 7.49% in a range of 7.31% to 7.67%; and
c) a forecast revenue requirement to be recovered from electrical rates, following implementation of the proposals set out in paragraphs 11 of the Application, of $661,467,000 for 2019 and $664,118,000 for 2020.

Additionally, the Company proposes that the Board approve the addition of a new service offering for LED street and area lighting and a corresponding amendment to Clause II.3 of the Rate Stabilization Clause for reasons set out in the evidence filed in support of the Application.

We have reviewed the Company's proposed rates effective March 1, 2019. Specifically, the procedures we have performed include the following:

1. A recalculation of the revenue that results from using the revised rates, ensuring that it agrees with the revenue requirement submitted by the Company;

2. Agreement of the factors used in the revenue calculations (number of customers, energy and demand usage, etc.) to those presented by the Company;

3. Agreement of the rates used in the revenue calculations to those in the proposed Revised Schedule of Rates, Tolls and Charges;

4. A recalculation of the percentage increase in revenue by rate class and the percentage increase in individual rates, tolls and charges; and,

5. Agreement of the annual kilowatt-hours used in calculating the Rate Stabilization Adjustment set out in Exhibit 12 to the Company's filed evidence and recalculation of the monthly street lighting rates.

The following table compares July 1, 2017 rates to March 1, 2019 proposed rates by class including RSA and Municipal Tax Adjustment ("MTA"):

**Table 39: Existing and Proposed Rates, Tolls & Charges**

| | EXISTING RATES July 1, 2017 | PROPOSED RATES March 1, 2019 | CHANGE ($) | CHANGE (%) |
|---|---|---|---|---|
| **DOMESTIC** | | | | |
| Total Customers for Class (000's) | 231,639 | 234,419 | 2,780 | 1.20% |
| *DOMESTIC - RATE # 1.1* | | | | |
| Basic Customer Charge (Monthly) | | | | |
| Not Exceeding 200 AMP service | $16.04 | $16.23 | $0.19 | 1.18% |
| Exceeding 200 AMP Service | $21.04 | $21.23 | $0.19 | 0.90% |
| Energy Charge - All Kilowatt Hours (Cents/kWh) | $0.10604 | $0.10736 | $0.00132 | 1.24% |
| Minimum Monthly Charge | | | | |
| Not Exceeding 200 AMP service | $16.04 | $16.23 | $0.19 | 1.18% |
| Exceeding 200 AMP Service | $21.04 | $21.23 | $0.19 | 0.90% |
| Prompt Payment Discount | 1.50% | 1.50% | - | - |
| *DOMESTIC - RATE # 1.1S* | | | | |
| Basic Customer Charge (Monthly) | | | | |
| Not Exceeding 200 AMP service | $16.04 | $16.23 | $0.19 | 1.18% |
| Exceeding 200 AMP Service | $21.04 | $21.23 | $0.19 | 0.90% |
| Energy Charge - All Kilowatt Hours (Cents/kWh) | | | | |
| Winter Seasonal | $0.11557 | $0.11689 | $0.00132 | 1.14% |
| Non-Winter Seasonal | $0.09307 | $0.09439 | $0.00132 | 1.42% |
| Minimum Monthly Charge | | | | |
| Not Exceeding 200 AMP service | $16.04 | $16.23 | $0.19 | 1.18% |
| Exceeding 200 AMP Service | $21.04 | $21.23 | $0.19 | 0.90% |
| Prompt Payment Discount | 1.50% | 1.50% | - | - |
| ***G.S. 0-100 kW (110 kVA) - RATE # 2.1*** | | | | |
| Total Customers for Class (000's) | 22,522 | 22,882 | 360 | 1.60% |
| Basic Customer Charge (Monthly) | | | | |
| Umetered | $17.20 | $12.50 | -$4.70 | -27.33% |
| Single Phase | $21.20 | $20.50 | -$0.70 | -3.30% |
| Three Phase | $27.20 | $32.50 | $5.30 | 19.49% |
| Demand Charge Regular | | | | |
| Winter (kW) | $9.16 | $9.25 | $0.09 | 0.98% |
| Other (kW) | $6.66 | $6.75 | $0.09 | 1.35% |
| Energy Charge - All Kilowatt Hours (Cents/kWh) | | | | |
| First 3,500 kilowatt-hours | $0.10511 | $0.10640 | $0.00129 | 1.23% |
| All excess kilowatt-hours | $0.07746 | $0.07844 | $0.00098 | 1.27% |
| Maximum Monthly Charge | $0.18728 plus B.C.C. | $0.18957 plus B.C.C. | $0.00229 | 1.22% |
| Minimum Monthly Charge | | | | |
| Umetered | $17.20 | $12.50 | -$4.70 | -27.33% |
| Single Phase | $21.20 | $20.50 | -$0.70 | -3.30% |
| Three Phase | $33.20 | $32.50 | -$0.70 | -2.11% |
| Prompt Payment Discount | 1.50% | 1.50% | - | - |

**Table 39: Existing and Proposed Rates, Tolls & Charges (Cont`d)**

| | EXISTING RATES July 1, 2017 | PROPOSED RATES March 1, 2019 | CHANGE ($) | CHANGE (%) |
|---|---|---|---|---|
| *G.S. 110-1000 kVA - RATE # 2.3* | | | | |
| Total Customers for Class (000's) | 1,266 | 1,262 | -4 | -0.32% |
| Basic Customer Charge (Monthly) | $49.57 | $50.17 | $0.60 | 1.21% |
| Demand Charge | | | | |
| Winter (kVA) | $7.74 | $7.82 | $0.08 | 1.03% |
| Other (kVA) | $5.24 | $5.32 | $0.08 | 1.53% |
| Energy Charge (Cents/kWh) | | | | |
| First 150 kWh per kVA of demand (max 50,000) | $0.08894 | $0.09004 | $0.00110 | 1.24% |
| All Excess kWh | $0.07055 | $0.07143 | $0.00088 | 1.25% |
| Maximum Monthly Charge (Cents/kWh + BCC) | $0.18728 plus B.C.C. | $0.18957 plus B.C.C. | $0.00229 | 1.22% |
| Minimum Monthly Charge | $49.57 | $50.17 | $0.60 | 1.21% |
| Prompt Payment Discount | 1.50% | 1.50% | - | - |
| *G.S. 1000 kVA and Over - RATE # 2.4* | | | | |
| Total Customers for Class (000's) | 61 | 60 | -1 | -1.64% |
| Basic Customer Charge (Monthly) | $86.39 | $87.44 | $1.05 | 1.22% |
| Demand Charge | | | | |
| Winter (kVA) | $7.46 | $7.53 | $0.07 | 0.94% |
| Other (kVA) | $4.96 | $5.03 | $0.07 | 1.41% |
| Energy Charge (Cents/kWh) | | | | |
| First 75,000 kWh | $0.08564 | $0.08669 | $0.00105 | 1.23% |
| All Excess kWh | $0.06986 | $0.07071 | $0.00085 | 1.22% |
| Maximum Monthly Charge (Cents/kWh + BCC) | $0.18728 plus BCC | $0.18957 plus BCC | $0.00229 | 1.22% |
| Minimum Monthly Charge | $86.39 | $87.44 | $1.05 | 1.22% |
| Prompt Payment Discount | 1.50% | 1.50% | - | - |
| *STREET & AREA LIGHTING RATES* | | | | |
| Total Customers for Class (000's) | 10,962 | 11,060 | 98 | 0.89% |
| **FIXTURES** | | | | |
| *Sentinel/Standard* | | | | |
| High Pressure Sodium | | | | |
| 100W | $17.13 | $17.24 | $0.11 | 0.64% |
| 150W | $21.06 | $21.27 | $0.21 | 1.00% |
| 250W | $29.16 | $29.69 | $0.53 | 1.82% |
| 400W | $39.91 | $40.99 | $1.08 | 2.71% |
| Light Emitting Diode | | | | |
| LED 100 | N/A | $15.85 | $15.85 | N/A |
| LED 150 | N/A | $17.30 | $17.30 | N/A |
| LED 250 | N/A | $22.11 | $22.11 | N/A |
| LED 400 | N/A | $24.97 | $24.97 | N/A |
| *Post Top* | | | | |
| High Pressure Sodium | | | | |
| 100W | $18.49 | $18.57 | $0.08 | 0.43% |
| *Poles* | | | | |
| Wood | $6.29 | $6.72 | $0.43 | 6.84% |
| 30' Concrete or Metal, direct buried | $8.99 | $9.58 | $0.59 | 6.56% |
| 45' Concrete or Metal, direct buried | $14.71 | $15.71 | $1.00 | 6.80% |
| 25' Concrete or Metal,Post Top, direct buried | $6.69 | $7.05 | $0.36 | 5.38% |
| *Underground Wiring* | | | | |
| All sizes and types of fixtures | $15.34 | $16.38 | $1.04 | 6.78% |

**Based on our procedures, we find that the revenue requirement proposed by the Company is calculated based upon the revised Schedule of Rates, Tolls and Charges effective March 1, 2019 and the factors proposed in this Application.**

## System of Accounts

Section 58 of the *Public Utilities Act* permits the Board to prescribe the form of accounts to be maintained by the Company.

The objective of our review of the Company's accounting system and code of accounts was to ensure that it can provide information sufficient to meet the reporting requirements of the Board. We have observed that the Company has in place a well-structured, comprehensive system of accounts and reporting structure. The system allows for adequate flexibility to allow the Company to meet its own and the Board's reporting requirements.

On March 29, 2018, the Company filed a summary of revisions to its system of accounts with the Board, along with a copy of the revised System of Accounts as part of the Company's 2017 Annual Report. The Company indicated that the revisions principally relate to minor wording changes to improve clarity and accuracy of account descriptions. There was also the reinstatement of two accounts whereby they were inadvertently deleted in a previous year, and as well as a deletion of one account related to the Weather Normalization Reserve. We have confirmed with the Company that no further changes have been made since this time.

**Based upon our review of the Company's financial records, we have found that they are in compliance with the system of accounts prescribed by the Board. The system of accounts is comprehensive and well-structured and provides adequate flexibility for reporting purposes.**

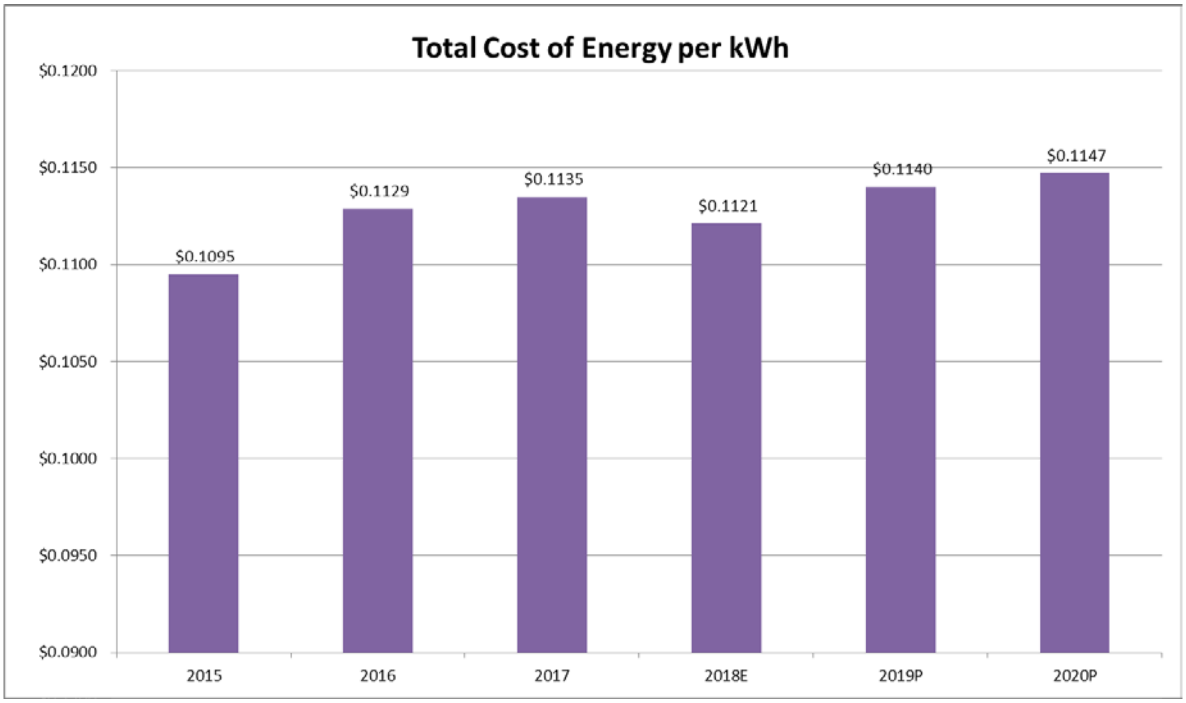
**Newfoundland Power Inc.** **Schedule 1**

**Comparison of Total Cost of Energy to kWh Sold**

**(000)'s**

| Year | kWh sold | Operating Expenses | Purchased Power | Depreciation / Deferrals | Finance Charges | Income Taxes | Net Income | Total Cost of Energy | Cost per kWh |
|---|---|---|---|---|---|---|---|---|---|
| **2015** | 5,957,000 | $ 81,512 | $ 422,095 | $ 55,841 | $ 35,161 | $ 16,529 | $ 41,113 | $ 652,251 | $ 0.1095 |
| **2016** | 5,950,000 | $ 75,292 | $ 443,311 | $ 57,254 | $ 34,643 | $ 18,152 | $ 42,887 | $ 671,539 | $ 0.1129 |
| **2017** | 5,922,000 | $ 76,954 | $ 440,249 | $ 56,455 | $ 34,894 | $ 19,424 | $ 43,988 | $ 671,964 | $ 0.1135 |
| **2018E** | 5,915,000 | $ 75,649 | $ 432,443 | $ 58,769 | $ 35,768 | $ 18,137 | $ 42,417 | $ 663,183 | $ 0.1121 |
| **2019P** | 5,883,000 | $ 71,759 | $ 429,949 | $ 62,999 | $ 36,232 | $ 20,320 | $ 49,421 | $ 670,680 | $ 0.1140 |
| **2020P** | 5,887,000 | $ 72,176 | $ 429,144 | $ 64,584 | $ 37,442 | $ 21,078 | $ 50,938 | $ 675,362 | $ 0.1147 |

(1) 2015 to 2018 is based on information provided in Exhibit 3 of the supporting materials to the GRA.
(2) 2019 to 2020 is based on information provided in Exhibit 5 of the Supporting Materials to the GRA.
(3) Figures presented excludes non-regulated activity.

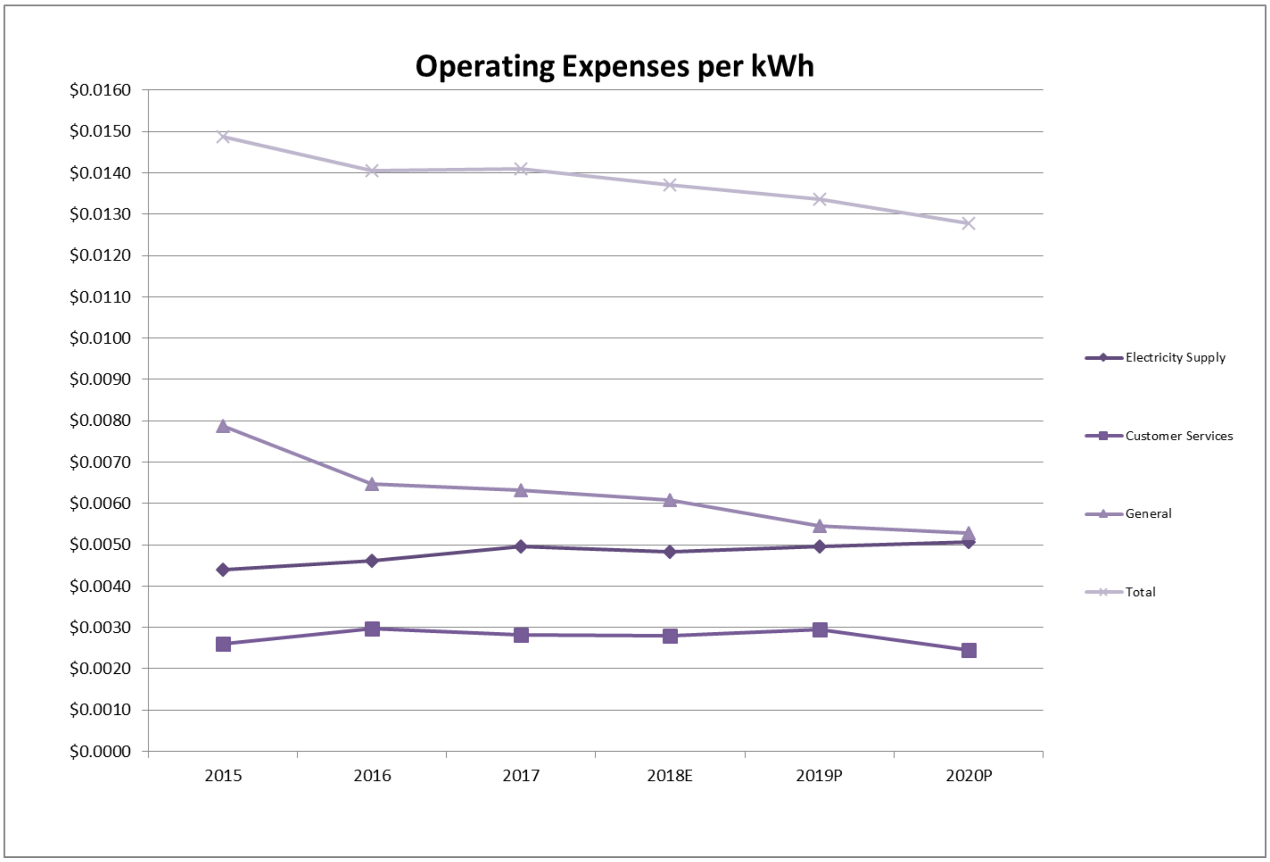



Grant Thornton

**Newfoundland Power Inc.** **Schedule 2**
**Comparison of Gross Operating Expenses to kWh Sold**
**(000's)**

| | | Electricity Supply | | Customer Services (2) | | General (3) | | Totals | |
|---|---|---|---|---|---|---|---|---|---|
| Year | kWh sold | Cost | Cost per kWh | Cost | Cost per kWh | Cost | Cost per kWh | Cost | Cost per kWh |
| 2015 | 5,957,000 | $ 26,191 | $0.0044 | $ 15,447 | $0.0026 | $ 46,901 | $0.0079 | $ 88,539 | $0.0149 |
| 2016 | 5,950,000 | $ 27,400 | $0.0046 | $ 17,663 | $0.0030 | $ 38,500 | $0.0065 | $ 83,563 | $0.0140 |
| 2017 | 5,922,000 | $ 29,352 | $0.0050 | $ 16,754 | $0.0028 | $ 37,371 | $0.0063 | $ 83,477 | $0.0141 |
| 2018E | 5,915,000 | $ 28,520 | $0.0048 | $ 16,583 | $0.0028 | $ 35,921 | $0.0061 | $ 81,024 | $0.0137 |
| 2019P | 5,883,000 | $ 29,200 | $0.0050 | $ 17,354 | $0.0029 | $ 32,119 | $0.0055 | $ 78,673 | $0.0134 |
| 2020P | 5,887,000 | $ 29,768 | $0.0051 | $ 14,394 | $0.0024 | $ 31,117 | $0.0053 | $ 75,279 | $0.0128 |

(1) Based on information in Exhibit 1 of the supporting materials to the GRA.
(2) Customer Service presented includes costs prior to the allocation to the CDM cost deferral account.
(3) General expenses presented include employee future benefits costs.
(4) Figures presented excludes non-regulated activity.



Grant Thornton

An instinct for growth™

www.GrantThornton.ca

**Audit • Tax • Advisory**