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# Board of Commissioners of Public Utilities

Financial Consultants Report
2018 Annual Financial Review of
Newfoundland Power Inc.

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# Restrictions, Qualifications and Independence

### Purpose

This report was prepared for the Board of Commissioners of Public Utilities in Newfoundland and Labrador. The purpose of our engagement was to present our observations, findings and recommendations with respect to our 2018 annual financial review of Newfoundland Power Inc.

### Restrictions and Limitations

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's 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.

## Executive Summary

This report to the Board of Commissioners of Public Utilities ("the Board") presents our observations, findings and recommendations with respect to our 2018 Annual Financial Review of Newfoundland Power Inc. ("the Company") ("Newfoundland Power"). Below is a summary of the key observations and findings included in our report.

The average rate base for 2018 was $1,117,341,000 which is an increase of $25,087,000 (2.30%) over the average rate base for 2017 of $1,092,254,000. The Company's calculation of the return on average rate base for 2018 was 7.13% (2017 – 7.22%) compared to an approved rate of return of 7.04%. The actual rate of return was within the range approved by the Board (6.86% to 7.22%). The calculations of average rate base and rate of return on average rate base are in accordance with established practice and Board orders.

The Company's calculation of average common equity for 2018 was $495,374,000 (2017 - $486,557,000). The Company's actual return on average common equity for the year ended December 31, 2018 was 8.76% (2017 – 8.93%). In Order No. P.U. 32 (2007) the Board ordered that where in a given year the actual rate of return on equity (ROE) is greater than 50 bps above the test year calculation of the cost of equity for the same year (or as determined by the Automatic Adjustment Formula outside a test year), the Company must file a report with its annual return explaining the facts and circumstances contributing to the difference. In 2018 the cost of common equity was 8.50% as per Order No. P.U. 18 (2016). The actual return on average common equity for 2018 was 8.76% as noted above. This return was within the 50-basis point trigger and as such no report was required.

The actual capital expenditures (excluding capital projects carried forward from prior years) were 1.8% over budget in 2018. The capital expenditures were over the approved budget (including projects carried over from prior years) on a net basis by $2,913,000 (2.36%). However, for each category of expenditure, the variances ranged from an over-budget of 64.14% to an under-budget of 65.33%.

The Company experienced a 0.03% decrease in revenue from rates in 2018 as compared to 2017. The decrease is primarily due to the impact of lower electricity sales and a 0.7% customer rate decrease effective July 1, 2017.

Overall, net operating expenses decreased by $1,965,000 from 2017 to 2018. Significant operating expense variances are discussed in our report. We conducted an examination of other costs including purchased power, depreciation, interest and income taxes and have noted that nothing has come to our attention to indicate that these costs for 2018 are unreasonable.

Our review of non-regulated expenses resulted in nothing coming to our attention to indicate that the amounts reported are unreasonable or not in accordance with Board Orders.

Our analysis of the Company's regulatory assets and liabilities indicated that all were in accordance with applicable Board Orders.

Based on our review, the 2018 Pension Expense Variance Deferral Account (PEVDA) operated in accordance with Order No. P.U. 43 (2009).

Based on our review, the 2018 Other Post-Employment Benefits Cost Variance Deferral Account (OPEBVDA) operated in accordance with Order No. P.U. 31 (2010).

The Company continues to undertake initiatives aimed at improving reliability of service and efficiency of operations as is summarized in the Section entitled 'Productivity and Operating Improvements'. During 2018 the Company met five out of nine of its planned performance measures. The Company fell short of its targets in the following categories: "SAIDI", "% of Satisfied Customers as measured by Customer Satisfaction Survey", "All Injury/Illness Frequency Rate" and "Gross Operating Cost/Customer".

# Introduction

This report to the Board of Commissioners of Public Utilities presents our observations, findings and recommendations with respect to our 2018 Annual Financial Review of Newfoundland Power Inc.

***Scope and Limitations***

Our analysis was carried out in accordance with the following Terms of Reference:

1. Examine the Company's system of accounts to ensure that it can provide information sufficient to meet the reporting requirements of the Board.

2. Review the Company's calculations of return on rate base, return on equity, embedded cost of debt, capital structure and interest coverage to ensure that they are in compliance with Board Orders.

3. Conduct an examination of operating and administrative expenses, purchased power, depreciation, interest and income taxes to review them in relation to sales of power and energy and their compliance with Board Orders.

   Our examination of the foregoing will include, but is not limited to, the following expense categories:

   - advertising,
   - bad debts (uncollectible bills),
   - company pension plan,
   - costs associated with curtailable rates,
   - conservation and demand management,
   - donations,
   - general expenses capitalized (GEC),
   - income taxes,
   - interest and finance charges,
   - membership fees,
   - miscellaneous,
   - non-regulated expenses,
   - purchased power,
   - salaries and benefits,
   - travel, and
   - amortization of regulatory costs.

4. Review intercompany charges and assess compliance with Board Orders including requirements for additional reports pursuant to Order No. P.U. 19 (2003) and Order No. P.U. 32 (2007).

5. Examine the Company's 2018 capital expenditures in comparison to budgets and prior years and follow up on any significant variances. Included in this review will be an analysis of amounts included in 'Allowance for Unforeseen Items'.

6. Review the Company's rates of depreciation and assess their compliance with the Gannett Fleming Depreciation Study included in the Company's 2016-17 GRA and review the calculations of depreciation expense.

7. Review Minutes of Board of Directors' meetings.

8. Review the Company's initiatives and efforts with respect to productivity improvements, rationalization of operations and expenditure reductions. Inquire as to the Company's reporting on Key Performance Indicators.

9. Conduct an examination of the changes to deferred charges and regulatory deferrals.

10. Conduct an examination of the Pension Expense Variance Deferral Account to assess compliance with Order No. P.U. 43 (2009).

11. Conduct an examination of the OPEBs Cost Variance Deferral Account and the amortization of the Company's transitional balance to assess compliance with Order No. P.U. 31 (2010).

The nature and extent of the procedures which we performed in our financial review varied for each of the items listed above. In general, our procedures were comprised of:

- inquiry and analytical procedures with respect to financial information as provided by the Company; and
- examination of, on a test basis where appropriate, documentation supporting amounts included in the Company's records.

The procedures undertaken in the course of our financial review do not constitute an audit of the Company's financial information and consequently, we do not express an opinion on the financial information as provided by the Company.

The financial statements of the Company for the year ended December 31, 2018 have been audited by Deloitte LLP, Chartered Professional Accountants, who have expressed their unqualified opinion on the fairness of the statements in their report dated February 14, 2019. 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.

## 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 organization/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, 2019, the Company filed a revised system of accounts as part of its 2018 Annual Report. In submitting these changes, the Company noted that the revisions were mainly due to accounts approved by the Board over the last two years.

**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.**

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

***Scope:*** ***Review the Company's calculations of return on rate base, return on equity, capital structure and interest coverage to ensure that they are in compliance with Board Orders.***

**Calculation of Average Rate Base**

The Company's calculation of its average rate base for the year ended December 31, 2018 which is included on Return 3 of the annual report to the Board was computed using the Asset Rate Base Method ("ARBM"). The average rate base for 2018 was $1,117,341,000 which is an increase of $25,087,000 (2.30%) over the average rate base for 2017 of $1,092,254,000. The increase was primarily a result of an increase in plant investment.

Our procedures with respect to verifying the calculation of the average rate base were directed towards the verification 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 audited financial statements and internal accounting records, where applicable;

- agreed component data (capital expenditures; depreciation; etc.) to supporting documentation;

- checked the clerical accuracy of the continuity of the rate base for 2018; and

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

The following table summarizes the components of the average rate base for 2017 and 2018 (all figures shown are averages):

| (000)'s | 2018 | 2017 |
|---|---|---|
| **Net Plant Investment (average)** | | |
| Plant Investment | $ 1,834,415 | $ 1,772,877 |
| Accumulated Depreciation | (739,030) | (709,985) |
| CIAC's | (38,474) | (37,234) |
| | 1,056,911 | 1,025,658 |
| **Additions to Rate Base (average)** | | |
| Deferred Charges (a) | 90,963 | 93,498 |
| Cost Recovery Deferral for Hearing Costs (b) | 171 | 512 |
| Cost Recovery Deferral – Conservation (c) | 15,003 | 12,710 |
| Customer Finance Programs (d) | 1,978 | 1,419 |
| Demand Management Incentive Account (e) | 745 | 745 |
| Weather Normalization Reserve (f) | 3,144 | 3,246 |
| | 112,004 | 112,130 |
| **Deductions from Rate Base (average)** | | |
| Other Post-Employment Benefits (g) | 54,848 | 49,334 |
| Customer Security Deposits (h) | 1,069 | 926 |
| Accrued Pension Obligation (i) | 5,294 | 5,429 |
| Deferred Income Taxes (j) | 4,401 | 3,051 |
| Cost Recovery Deferral – 2016 Cost Recovery Deferral (k) | 362 | 1,084 |
| | 65,974 | 59,824 |
| **Average Rate Base before Allowances** | 1,102,941 | 1,077,964 |
| **Rate Base Allowances** | | |
| Materials and Supplies | 6,184 | 6,137 |
| Cash Working Capital | 8,216 | 8,153 |
| | 14,400 | 14,290 |
| **Average Rate Base** | $ 1,117,341 | $ 1,092,254 |

(a) The Company's rate base is determined using the Asset Rate Base Method which incorporates average deferred charges into the calculation of rate base. The total average deferred charges of $90,963,000 (2017 - $93,498,000) included in the 2018 rate base consists of average deferred pension costs of $90,848,000 (2017 - $93,396,000) and credit facility costs of $115,000 (2017 - $102,000). The Company has included a schedule of these costs in Return 8.

(b) In Order No. P.U. 18 (2016) the Board approved the creation of a Hearing Cost Deferral Account to recover over 30 months, commencing July 1, 2016, hearing costs related to the 2016/2017 GRA in the amount of $1,200,000. During 2016, the Company deferred $853,000, $347,000 lower than the approved amount, of 2016/2017 GRA hearing costs. Amortization of approximately $341,000 was recorded in 2017 and 2018, relating to these costs. The 2018 average rate base includes an addition of $171,000 (2017 - $512,000) which represents the unamortized average balance of the original $853,000.

(c) In Order No. P.U. 13 (2013) the Board approved Newfoundland Power's proposed change in definition of conservation program costs and the deferral and amortization of annual conservation program costs over seven years with recovery through the Rate Stabilization Account. The actual costs incurred and deferred in 2013 were $2,937,000 ($2,085,000 after tax) resulting in annual amortization of $298,000 in 2014. The actual costs incurred and deferred in 2014 were $4,436,000 ($3,150,000 after tax) resulting in additional annual amortization of $450,000 to commence in 2015. The actual costs incurred and deferred in 2015 were $4,611,000 ($3,274,000 after tax) resulting in additional annual amortization of $468,000 to commence in 2016. The actual costs incurred and deferred in 2016 were $7,200,000 ($5,040,000 after tax) resulting in additional annual amortization of $720,000 to commence in 2017. The actual costs incurred and deferred in 2017 were $6,759,000 ($4,731,000 after tax) resulting in additional annual amortization of $676,000 to commence in 2018. The actual costs incurred and deferred in 2018 were $6,239,000 ($4,367,000 after tax) resulting in additional annual amortization of $624,000 to commence in 2018. Included in the calculation of the average rate base for 2018 is $15,003,000 (2017 - $12,710,000) related to this deferral.

(d) Customer Finance Programs are comprised of loans provided to customers related to customer conservation programs and contributions in aid of construction. The 2018 average rate base incorporates $1,978,000 (2017 - $1,419,000) related to these programs.

(e) In Order No. P.U. 10 (2018) the Board approved the disposition of the 2017 balance of the Demand Incentive Account of $2,128,000 ($1,490,000 after tax) by means of a debit to the Rate Stabilization Account as of March 31, 2018. In 2018 there was a $1,490,000 balance within the Demand Incentive Account, which was transferred to the RSA. The 2018 average rate base incorporates $745,000 (2017 - $745,000) related to this account. The 2018 balance of the Demand Incentive Account was $Nil as there was no supply cost variance outside the Deadband, which is defined as $728,000 (plus/minus 1% of test year wholesale demand charges).

(f) During 2018, the Weather Normalization reserve was impacted by the following:

Transfer to RSA:

i. In Order No. P.U. 13 (2013) the Board approved annual balances in the Weather Normalization reserve be recovered from or credited to customers through the Rate Stabilization Account. This resulted in a transfer increase to the reserve of $4,771,000 in 2018 (2017 – $1,721,000 increase).

Other transfers:

i. $90,000 transfer decrease (2017 – $112,000 increase) to the reserve related to the after tax impact of the Degree Day Normalization Reserve Transfer.
ii. $1,427,000 transfer decrease (2017 - $4,883,000 decrease) to the reserve related to the after tax impact of the Hydro Production Equalization Reserve transfer.

The net impact was a net decrease to the reserve of $3,254,000 (2017 - $3,050,000 increase). The ending balance in this reserve account totaled ($1,517,000) compared to a balance of ($4,771,000) at December 31, 2017 (an average of ($3,144,000) for 2018 (2017 – ($3,246,000)).

(g) Other Post-Employment Benefits is equal to the difference, at December 31, 2018, between the OPEBs liability of $81,640,000 and the OPEBs asset of $24,528,000. The calculation of the 2018 average rate base of $54,848,000 is equal to the average of the December 31, 2018 net liability of $57,112,000 and the December 31, 2017 net liability of $52,584,000.

(h) Customer Security Deposits are comprised of security deposits received from customers for electrical services in accordance with the Board-approved Schedule of Rates, Rules and Regulations. The calculation of the 2018 average rate base incorporates $1,069,000 (2017 - $926,000) related to customer security deposits.

(i) The 2018 average rate base calculation incorporates $5,294,000 (2017 - $5,429,000) of Accrued Pension Obligation. This obligation is a result of executive and senior management supplemental pension benefits comprised of a defined benefit plan and a defined contribution plan. The defined benefit plan was closed to new entrants in 1999.

(j) In Order No. P.U. 32 (2007) the Board approved the Company's adoption of the accrual method of accounting for income tax related to pension costs. In Order No. P.U. 31 (2010) the Board approved the Company's adoption of the accrual method of accounting for other post-employment benefits (OPEBs) costs and income tax related to OPEBs. The balance of deferred income taxes related to pension costs and OPEBs included in the 2018 average rate base is ($3,008,000) and ($14,537,000) respectively. The remaining balance of the deferred income tax liability in the amount of $21,946,000 relates to capital assets. This results in an average balance for deferred income tax liability of $4,401,000 (2017 - $3,051,000).

(k) In Order No. P.U. 18 (2016) the Board approved the deferral over a 30-month period of a $2,580,000 (before tax) over-recovery of revenue in 2016 due to a July 1, 2016 rate implementation date. During 2016, the Company deferred the after tax amount of ($1,806,000). Amortization of approximately ($722,000) and ($723,000) was recorded in 2017 and 2018 respectively, relating to this over-recovery of revenue. The 2018 average rate base includes deduction of $362,000 (2017 - $1,084,000) which represents the unamortized average balance of the original $1,806,000.

The net change in the Company's average rate base from 2017 to 2018 can be summarized as follows:

| (000's) | 2018 | 2017 |
|---|---|---|
| Average rate base - opening balance | **$ 1,092,254** | $ 1,061,044 |
| Change in average deferred charges and deferred regulatory costs | **139** | (268) |
| Average change in: | | |
| Plant in service | **61,539** | 69,399 |
| Accumulated depreciation | **(29,045)** | (28,243) |
| Contributions in aid of construction | **(1,241)** | (2,068) |
| Weather normalization reserve | **(102)** | 180 |
| Other post-employment benefits | **(5,515)** | (6,688) |
| Future income taxes | **(1,351)** | (1,324) |
| Rate base allowances | **110** | (492) |
| Customer Finance Programs | **559** | 142 |
| Demand Management Incentive Acct | **-** | 745 |
| Other rate base components (net) | **(6)** | (173) |
| Average rate base - ending balance | **$ 1,117,341** | $ 1,092,254 |

**Based upon the results of the above procedures we did not note any discrepancies in the calculation of the 2018 average rate base, and therefore conclude that the 2018 average rate base included in the Company's annual report to the Board is accurate and in accordance with established practice and Board Orders.**

## Return on Average Rate Base

The Company's calculation of the return on average rate base is included on Return 13 of the annual report to the Board. The return on average rate base for 2018 was 7.13% (2017 – 7.22%). Our procedures with respect to verifying the reported return on average rate base included agreeing the data in the calculation to supporting documentation and recalculating the rate of return to ensure it is in accordance with established practice and Board Orders. For 2018, the return on average rate base is calculated in accordance with the methodology approved in Order No. P.U. 13 (2013).

The actual return on average rate base in comparison to the range of allowed return for each of the years from 2016 to 2018 is set out in the table below.

| | 2018 | 2017 | 2016 |
|---|---|---|---|
| Actual Return on Average Rate Base | 7.13% | 7.22% | 7.31% |
| Upper End of Range set by the Board | 7.22% | 7.37% | 7.39% |
| Lower End of Range set by the Board | 6.86% | 7.01% | 7.03% |

The Board approved the Company's rate of return on average rate base of 7.04% in a range of 6.86% to 7.22% for 2018 in Order No. P.U. 41 (2017). As noted above, the Company's actual return on average rate base for 2018 was 7.13% which was inside the range set by the Board.

The actual rate of return for 2017 was within the range set by the Board.

The actual rate of return for 2016 was within the range set by the Board.

**As a result of completing these procedures, we can advise that no discrepancies were noted and therefore conclude that the calculation of rate of return on average rate base included in the Company's annual report to the Board is in accordance with established practice.**

## Capital Structure

In Order No. P.U. 18 (2016) the Board reconfirmed its previous position as per Order No. P.U. 13 (2013) regarding the capital structure for Newfoundland Power Inc. and the Board has deemed that the proportion of common equity in the capital structure shall not exceed 45%.

The Company's capital structure for 2018 as reported in Return 24 is as follows:

| | 2018 Average | | | 2017 | 2016 |
|---|---|---|---|---|---|
| | | **(000's)** | **Percent** | Percent | Percent |
| Debt | **$** | **604,599** | **54.53%** | 54.22% | 54.17% |
| Preferred equity | | **8,914** | **0.80%** | 0.82% | 0.84% |
| Common equity | | **495,374** | **44.67%** | 44.96% | 44.99% |
| | **$** | **1,108,887** | **100%** | 100% | 100% |

Pursuant to Order No. P.U. 32 (2007), the Company did submit a schedule (Return 25) calculating the cost of embedded debt for the current year. It also indicated the variances in interest expense and average debt over the 2017 test year in Return 26. The embedded cost of debt for 2018 was 6.07% which represents a 5 bps decrease from the 2017 embedded cost of debt of 6.12%.

**Based on the information indicated above, we conclude that the capital structure included in the Company's annual report to the Board is in compliance with Order No. P.U. 18 (2016).**

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

The Company's calculation of average common equity and return on average common equity for the year ended December 31, 2018 is included on Return 27 of the annual report to the Board. The average common equity for 2018 was $495,374,000 (2017 - $486,557,000). The Company's actual return on average common equity for 2018 was 8.76% (2017 – 8.93%).

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 component data (earnings applicable to common shares; dividends; regulated earnings; etc.) to supporting documentation;
- checked the clerical accuracy of the continuity of book common equity per Order No. P.U. 40 (2005), including the deemed capital structure per Order No. P.U. 19 (2003), Order No. P.U. 32 (2007), Order No. P.U. 43(2009), Order No. P.U. 13 (2013), and Order No. P.U. 18 (2016).
- recalculated the rate of return on common equity for 2018 and ensured it was in accordance with established practice, Order No. P.U. 32 (2007), and Order No. P.U. 18 (2016).

In Order No. P.U. 32 (2007) the Board ordered that where in a given year the actual rate of return on equity (ROE) is greater than 50 bps above the test year calculation of the cost of equity for the same year (or as determined by the Automatic Adjustment Formula outside a test year), the Company must file a report with its annual return explaining the facts and circumstances contributing to the difference. In 2017 the cost of common equity was 8.50% as per Order No. P.U. 18 (2016). The actual return on average common equity for 2018 was 8.76% as noted above. This return was within the 50 basis point trigger and as such no report was required.

**Based on completion of the above procedures we did not note any discrepancies in the calculations of regulated average common equity or return on regulated average common equity.**

## Interest Coverage

The level of interest coverage experienced by the Company over the last three years is as follows:

| (000's) | 2018 | 2017 | 2016 |
|---|---|---|---|
| Net Income | **$ 41,744** | $ 41,526 | $ 40,508 |
| Income Taxes | **12,280** | 12,882 | 11,851 |
| Interest on long term debt | **35,788** | 35,013 | 34,846 |
| Interest during construction | **(951)** | (1,025) | (1,304) |
| Other interest and amortization of discount costs | **931** | 893 | 1,090 |
| **Total** | **$ 89,792** | $ 89,289 | $ 86,991 |
| | | | |
| Interest on long term debt | **$ 35,788** | $ 35,013 | $ 34,846 |
| Other interest and amortization of discount costs | **931** | 893 | 1,090 |
| **Total** | **$ 36,719** | $ 35,906 | $ 35,936 |
| | | | |
| **Interest Coverage (times)** | **2.4** | 2.5 | 2.4 |

The above table shows that the interest coverage decreased by 0.1 times from 2017 to 2018.

**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. The level of interest coverage realized for 2018 is 2.4 times.**

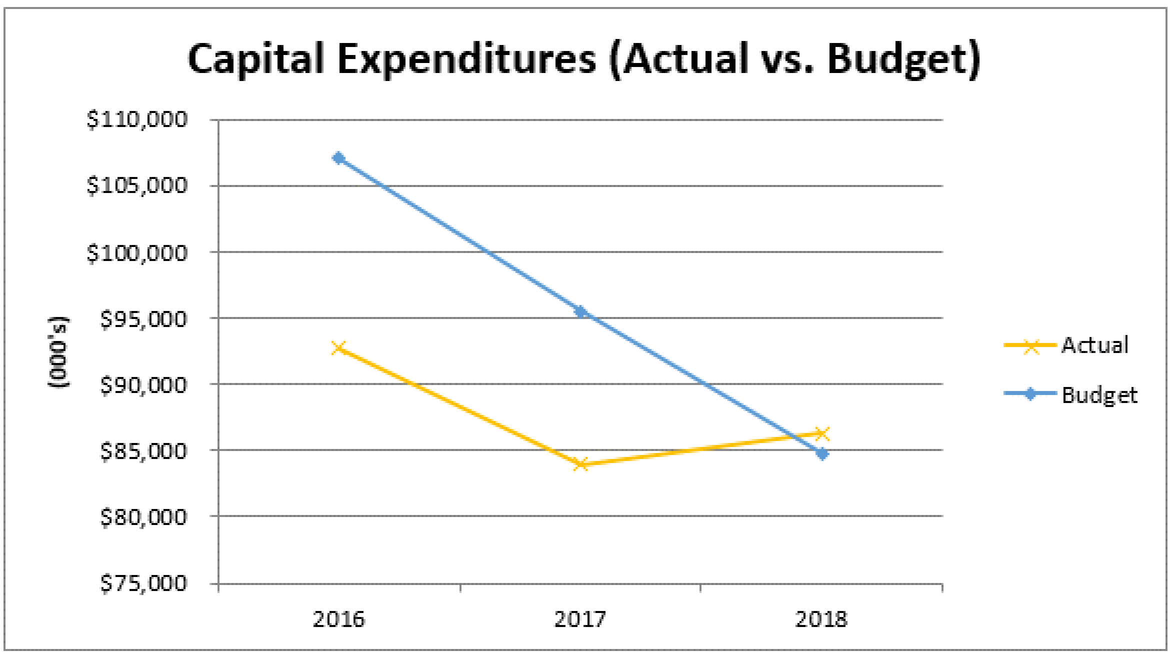
## Capital Expenditures

***Scope:*** ***Review the Company's 2018 capital expenditures in comparison to budgets and follow up on any significant variances.***

The following table details the actual versus budgeted capital expenditures (excluding capital projects carried forward from prior years) for the past three years from 2016 to 2018:

| ($000's) | 2016 | 2017 | 2018 | Notes |
|---|---|---|---|---|
| Actual | $ 92,727 | $ 83,921 | $ 86,285 | 1 |
| Budget | $ 107,028 | $ 95,521 | $ 84,776 | |
| Over (under) budget | (13.36%) | (12.14%) | 1.78% | |

Note 1: Total expenditures per the 2018 Capital Budget report includes the carryover amount of $2,825,000 for a total of $89,110,000. The carryover amount is made up of four projects included in the following categories: $130,000 to generation - hydro; $1,595,000 to generation - thermal; $498,000 to general property; $602,000 to information systems. According to the Company, these expenditures will occur in 2019.



The following table provides a summary of the capital expenditure activity in 2018 as reported in the Company's *"2018 Capital Expenditure Report"*:

| ($000's) | Capital Budget | | | Actual Expenditures | | |
|---|---|---|---|---|---|---|
| | Prior Years | 2018 | Total | Prior Years | 2018 | Total |
| 2018 Capital Projects (1) | $ - | $ 84,776 | $ 84,776 | $ - | $ 86,285 | $ 86,285 |
| 2017 Projects Carried to 2018 & Multi Year Projects | | | | | | |
| Facility Rehabilitation - 2017 (2) | 1,607 | - | 1,607 | 1,250 | 192 | 1,442 |
| Rose Blance Plant Refurbishment - 2017 (3) | 3,281 | - | 3,281 | 2,453 | 210 | 2,663 |
| Tors Cove Plant Refurbishment - 2017 (4) | 1,476 | - | 1,476 | 301 | 881 | 1,182 |
| Substations Refurbishment and Modernization - 2017 | 10,350 | - | 10,350 | 10,027 | 749 | 10,776 |
| Transmission Line Rebuild - 2017 | 6,711 | - | 6,711 | 6,224 | 529 | 6,753 |
| Trunk Feeders - 2017 (5) | 1,834 | - | 1,834 | 861 | 434 | 1,295 |
| Meters - 2017 (6) | 4,391 | - | 4,391 | 3,625 | 300 | 3,925 |
| Purchase Vehicles and Aerial Devices - 2017 (7) | 3,456 | - | 3,456 | 3,553 | 271 | 3,824 |
| Distribution Reliability Initiative - Multi Year | 1,215 | - | 1,215 | 218 | 700 | 918 |
| St. John's Main Underground Refurbishment - Multi Year | 4,390 | - | 4,390 | 2,965 | 1,547 | 4,512 |
| | 38,711 | - | 38,711 | 31,477 | 5,813 | 37,290 |
| **Grand Total** | **$ 38,711** | **$ 84,776** | **$ 123,487** | **$ 31,477** | **$ 92,098** | **$ 123,575** |

(1) Approved by Order P.U. 37 (2017).
(2) The Company has noted that the favorable budget variance arose as detailed engineering revealed less concrete deterioration than originally anticipated.
(3) The Company has noted that the favorable variance was related to a contingency for additional slope stabilization which was not required.
(4) The Company has noted that the favorable budget variance primarily resulted from a decision to defer automation of unit G1. As a result of this change the Company eliminated the valve replacement element of the project.
(5) The Company has noted that the favorable budget variance is a result of efficiencies from specialized equipment designed for work in customer's yards. Additionally, the final design of the King's Bridge Substation required less underground infrastructure than originally planned and the vault replacement at the Terra Nova Tel building was not required as the building owner advised of plans to renovate the building.
(6) The Company has noted that the favorable budget variance was principally due to the majority of meter installations taking place in urban areas resulting in a lower cost of installation.
(7) The Company has noted that the unfavorable budget variance is related to modifications and related delays to a heavy fleet vehicle to meet the required specifications.

A breakdown of the total capital expenditures and budget with variances by asset category is as follows:

| ($000's) | 2018 Budget (1) | 2018 Actuals (2) | Variance | Carryover (3) | Variance Including Carryover | % |
|---|---|---|---|---|---|---|
| Generation - Hydro | $ 8,483 | $ 7,635 | (848) | $ 130 | (718) | (8.46%) |
| Generation - Thermal | 6,301 | 4,861 | (1,440) | 1,595 | 155 | 2.46% |
| Substation | 23,138 | 23,438 | 300 | - | 300 | 1.30% |
| Transmission | 13,879 | 14,559 | 680 | - | 680 | 4.90% |
| Distribution | 50,687 | 52,983 | 2,296 | - | 2,296 | 4.53% |
| General property | 2,663 | 2,224 | (439) | 498 | 59 | 2.22% |
| Transportation | 6,818 | 7,418 | 600 | - | 600 | 8.80% |
| Telecommunications | 198 | 325 | 127 | - | 127 | 64.14% |
| Information systems | 6,570 | 6,018 | (552) | 602 | 50 | 0.76% |
| Unforeseen | 750 | 260 | (490) | - | (490) | (65.33%) |
| General expenses capitalized | 4,000 | 3,854 | (146) | - | (146) | (3.65%) |
| **Total** | **$ 123,487** | **$ 123,575** | **$ 88** | **$ 2,825** | **$ 2,913** | **2.36%** |

1 - Includes prior years projects and current year budgeted amounts as there were projects incomplete at the previous year ends.
2 - 2018 actuals include the total expense for projects carried forward from the years 2016 to 2017.
3 - Represents $2,825,000 included in the 2019 budget.

As indicated in the table, capital expenditures were less than the approved budget (including projects carried over from prior years) on a net basis by $88,000 and by $2,913,000 (2.36%) when carryover amounts are taken into account. However, for each category of expenditure, the variances ranged from an over-budget of 64.14% for the Telecommunications category to an under-budget of 65.33% for the Unforeseen category. As the variances within the table are for category totals it should be noted that individual project variances will differ from those listed. A breakdown by project of the carryover amounts from the table above is as follows:

| Project | Carryover (000's) |
|---|---|
| Facility Rehabilitation | 130 |
| Duffy Place Roof Replacement | 498 |
| Purchase Mobile Generation | 1,595 |
| Outage Management System | 602 |
| **Total Carryover** | **$ 2,825** |

The Company has provided detailed explanations on budget to actual variances in its “2018 Capital Expenditure Report”. For a complete review of the budget variance we refer the reader to this report, Appendix A.

*Adherence to Capital Budget Application Guidelines*

Based on our review, the Company's 2018 capital expenditures are in accordance with the Capital Budget Application Guidelines Policy #1900.6 Sections A and C as noted below:

- Under Section A, as required, the Company filed its annual capital budget application by July 15th and followed appropriate guidelines for the format of the application submitted.

- Under Section C, as required, the Company filed its annual capital expenditures report by the deadline of March 1st and included within its explanations of variances greater than both $100,000 and 10%.

- Section C of the guidelines also notes that "should the overall variance in any two years exceed 10% of the budgeted total the report should address whether there should be changes to the forecasting or capital budgeting process which should be considered". This is interpreted to refer to the variance exceeding 10% in two consecutive years. The variance was -12.14% in 2017 and 1.78% in 2018 resulting in no additional reporting requirements.

The allowance for unforeseen items account was used at a cost of $260,000 in 2018. According to the Company, these costs were incurred to repair water damage sustained to a Mobile Diesel Generator MDG3 which rendered it inoperable. The generator is an important component of the Company's generation fleet used to minimize customer interruptions in emergency situations. Repairs to the generator entailed a full teardown of the engine and refurbishment or replacement of damaged components. In addition, a modified exhaust flap was installed to prevent future water damage. After repairs and modifications were completed, the generator was tested and returned to service.

<u>Capital Expenditure Reports</u>

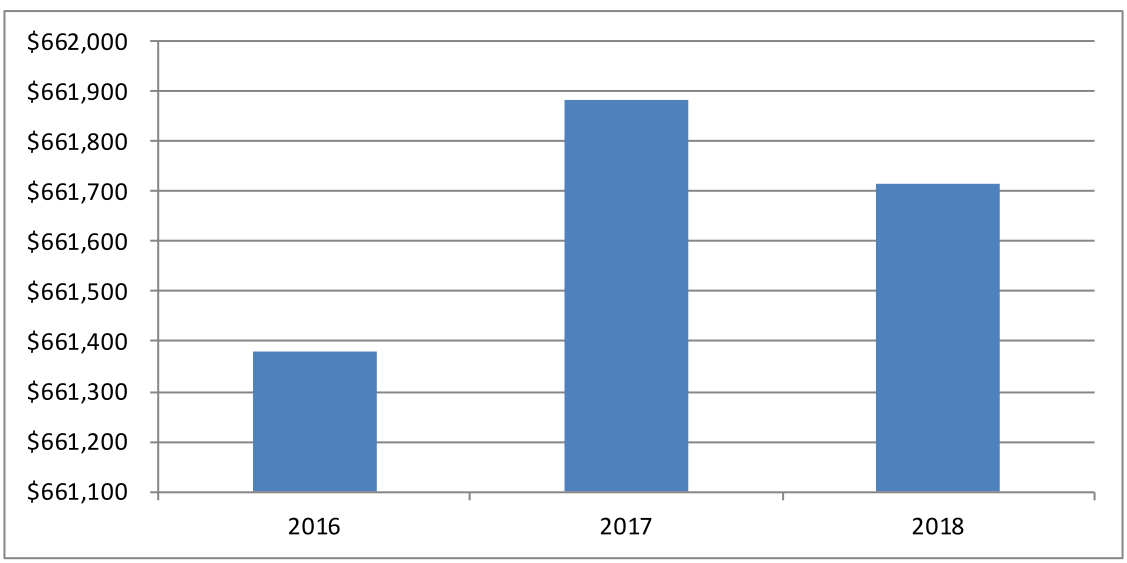
Confirmation was received from the Board that the Company filed quarterly Capital Expenditure reports for the 2018 calendar year.

## Revenue from rates

***Scope:*** ***Review the Company's 2018 revenue from rates in comparison to prior years and follow up on any significant variances.***

We have compared the actual revenues from rates for 2016 to 2018 to assess any significant trends. The results of this analysis of revenue by rate class are as follows:

| ($000's) | 2016 | 2017 | 2018 |
|---|---|---|---|
| Residential | $ 420,159 | $ 422,237 | $ 419,389 |
| General Service | | | |
| 0-100 kW | 88,362 | 88,507 | 90,364 |
| 110-1000 kVA | 96,404 | 95,565 | 97,338 |
| Over 1000 kVA | 38,021 | 37,099 | 35,725 |
| Streetlighting | 15,928 | 16,149 | 16,255 |
| Discounts forfeited | 2,507 | 2,327 | 2,643 |
| Revenue from rates | $ 661,381 | $ 661,884 | $ 661,714 |
| Year over year percentage change | 3.29% | 0.08% | -0.03% |




The above graph demonstrates that the Company has seen a 0.03% decrease in revenue from rates in 2018 as compared to 2017. The decrease is primarily due to the impact of lower electricity sales and a 0.7% customer rate decrease effective July 1, 2017. For residential sales there was a decrease of 0.68% in 2018 revenue from 2017.

The comparison by rate class of 2018 actual revenues to 2018 budget is as follows:

| ($000's) | 2017 | 2018 | 2018 Plan | Actual - Plan Variance | % |
|---|---|---|---|---|---|
| Residential | $ 422,237 | $ 419,389 | $ 424,341 | $ (4,952) | (1.17%) |
| General Service | | | | | |
| 0-100 kW | 88,507 | 90,364 | 88,384 | 1,980 | 2.24% |
| 110-1000 kVA | 95,565 | 97,338 | 96,358 | 980 | 1.02% |
| Over 1000 kVA | 37,099 | 35,725 | 35,481 | 244 | 0.69% |
| Streetlighting | 16,149 | 16,255 | 16,167 | 88 | 0.54% |
| Discounts forfeited | 2,327 | 2,643 | 2,733 | (90) | (3.29%) |
| Total revenue from rates | $ 661,884 | $ 661,714 | $ 663,464 | $ (1,750) | (0.26%) |

We have also compared the 2018 budget energy sales in GWh to the actual sold in 2018:

| | 2017 | 2018 | 2018 Plan | Actual - Plan Variance | % |
|---|---|---|---|---|---|
| Residential | 3,644.8 | 3,593.0 | 3,683.0 | (90.0) | (2.44%) |
| General Service | | | | | |
| 0-100 kW | 793.6 | 805.4 | 795.2 | 10.2 | 1.28% |
| 110-1000 kVA | 1,010.2 | 1,022.9 | 1,021.2 | 1.7 | 0.17% |
| Over 1000 kVA | 440.8 | 422.0 | 426.6 | (4.6) | (1.08%) |
| Streetlighting | 32.8 | 32.8 | 33.1 | (0.3) | (0.91%) |
| Total | 5,922.2 | 5,876.1 | 5,959.1 | (83.0) | (1.39%) |

Actual 2018 revenue from rates was lower than 2018 Plan with an overall decrease in actual sales of $1,750,000 (0.26%) from the 2018 Plan. There was a 1.39% decrease in GWh sold in 2018 compared to 2018 Plan. The largest variance in revenue can be seen in the Residential and 0-100 KV class where revenues decreased by $4,952,000 (1.17%) and increased by $1,980,000 (2.24%) respectively.

## Operating and General Expenses

***Scope: Conduct an examination of operating and general expenses to assess their reasonableness and prudence in relation to sales of power and energy and their compliance with Board Orders.***

| (000's) | Actual 2018 | Actual 2017 | Actual 2016 | Variance 2018-2017 |
|---|---|---|---|---|
| Labour | $ 39,095 | $ 39,341 | $ 36,770 | $ (246) |
| Reclass OPEB labour cost | (1,125) | (1,173) | (981) | 48 |
| Total Labour | 37,970 | 38,168 | 35,789 | (198) |
| Vehicle expense | 1,682 | 1,854 | 1,797 | (172) |
| Operating materials | 1,511 | 1,528 | 1,425 | (17) |
| Inter-company charges | 1,847 | 2,002 | 2,145 | (155) |
| Plants, Subs, System Oper & Bldgs | 2,812 | 2,796 | 2,770 | 16 |
| Travel | 1,127 | 1,235 | 1,160 | (108) |
| Tools and clothing allowance | 1,254 | 1,234 | 1,161 | 20 |
| Miscellaneous | 1,619 | 1,879 | 1,821 | (260) |
| Conservation | 2,732 | 2,981 | 4,253 | (249) |
| Taxes and assessments | 1,286 | 1,252 | 1,214 | 34 |
| Uncollectible bills | 1,490 | 1,386 | 1,194 | 104 |
| Insurance | 1,306 | 1,326 | 1,293 | (20) |
| Severance & other employee costs | 68 | 102 | 47 | (34) |
| Education, training, employee fees | 403 | 339 | 275 | 64 |
| Trustee and directors' fees | 481 | 489 | 471 | (8) |
| Other company fees | 3,379 | 2,296 | 2,944 | 1,083 |
| Stationary & copying | 224 | 214 | 266 | 10 |
| Equipment rental/maintenance | 784 | 806 | 838 | (22) |
| Communications | 2,822 | 2,927 | 2,959 | (105) |
| Advertising | 1,443 | 1,592 | 1,519 | (149) |
| Vegetation management | 1,692 | 2,099 | 1,820 | (407) |
| Computing equipment & software | 1,628 | 1,451 | 1,359 | 177 |
| Total Other | 31,590 | 31,788 | 32,731 | (198) |
| Pension & early retirement program | 7,726 | 8,675 | 9,763 | (949) |
| OPEB's | 6,194 | 8,364 | 8,678 | (2,170) |
| Total employee future benefits | 13,920 | 17,039 | 18,441 | (3,119) |
| Total gross expenses | 83,480 | 86,995 | 86,961 | (3,515) |
| Transfers (GEC) | (2,781) | (2,847) | (2,955) | 66 |
| CDM amortization | 3,706 | 2,741 | 1,712 | 965 |
| Other contract expenses (Note 1) | 4,081 | | | |
| Deferred CDM program costs | (6,239) | (6,758) | (7,200) | 519 |
| Deferred regulatory costs | 341 | 341 | 172 | - |
| **Total net expenses** | $ 82,588 | $ 80,472 | $ 78,690 | $ (1,965) |

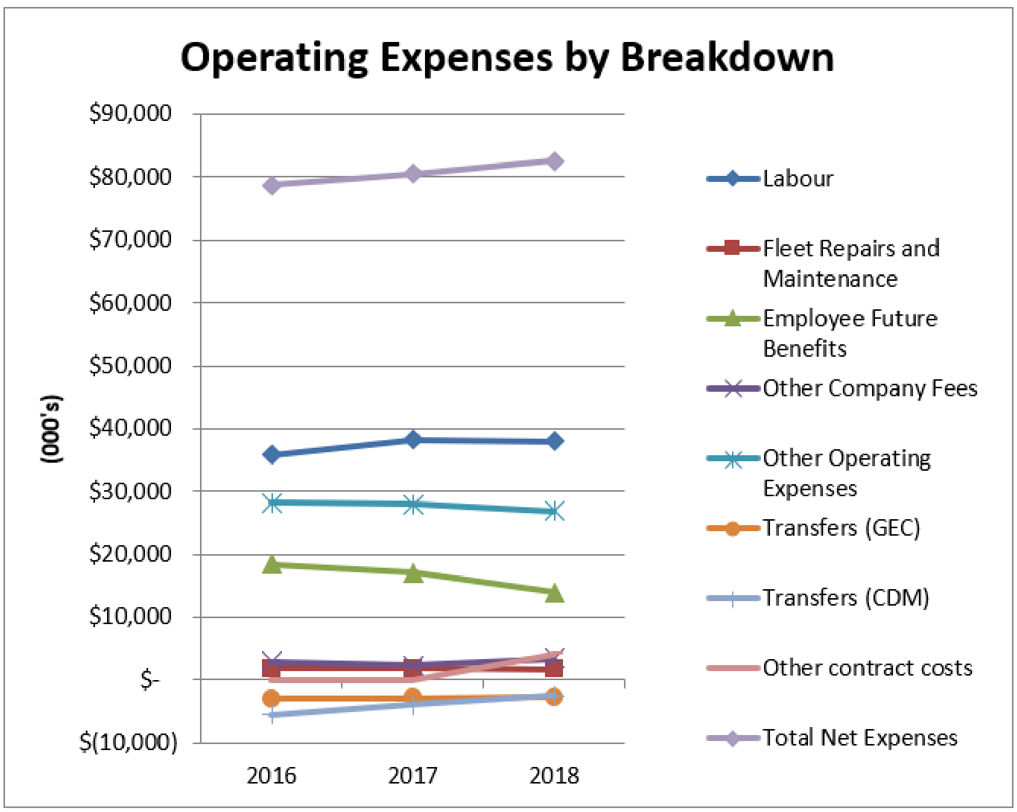
Note 1: According to the company, the presentation of other revenue was changed to be on a gross basis in 2018. This resulted in an increase in revenue and operating costs in 2018 related to work for telecommunciation companies. The 2017 and 2016 comparative have not been restated for this change in presentation.

The above table provides details of operating and general expenses (including non-regulated expenses) by “breakdown” for 2016, 2017, and 2018.

Overall, net operating expenses decreased by $1,965,000 from 2017 to 2018. Significant operating expense variances are discussed in our report. We conducted an examination of other costs including purchased power, depreciation, interest and income taxes and have noted that nothing has come to our attention to indicate that these costs for 2018 are unreasonable.

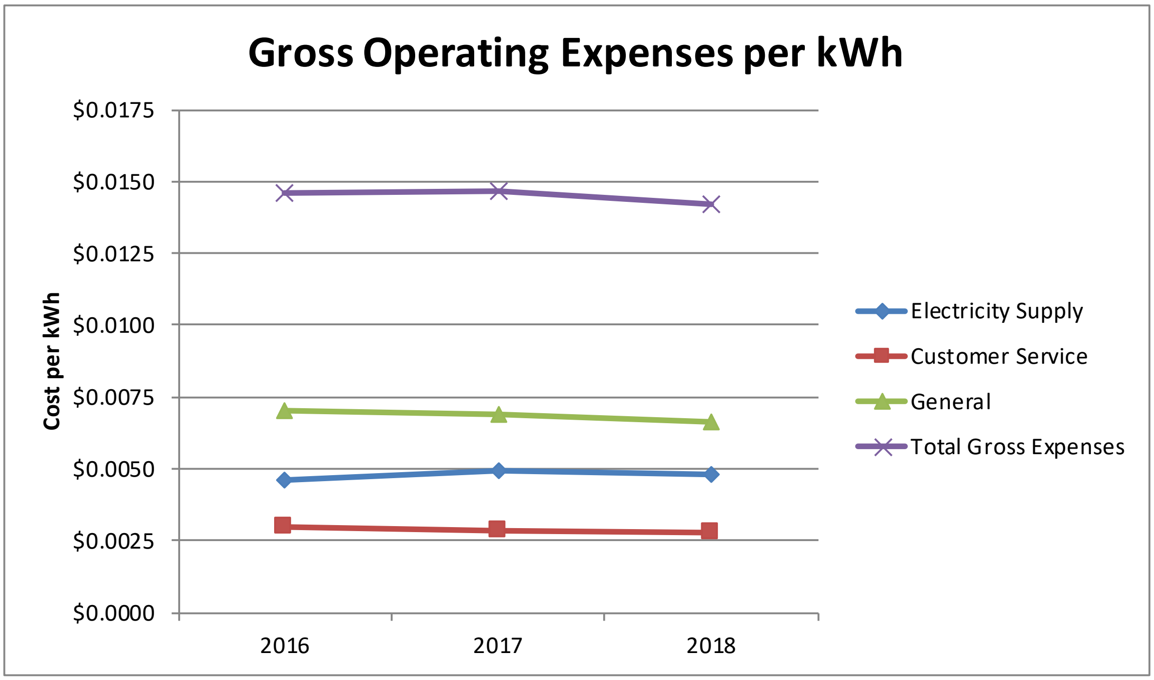
Our detailed review of operating expenses was conducted using the breakdown as documented in the above table. It should also be noted that our review is based upon gross expenses before allocation to GEC and CDM. The following table and graph show the trend in operating expenses by breakdown for the period 2016 to 2018.

| | Actual | | |
|---|---|---|---|
| **(000's)** | **2016** | **2017** | **2018** |
| Labour | $ 35,789 | $ 38,168 | $ 37,970 |
| Fleet Repairs and Maintenance | 1,797 | 1,854 | 1,682 |
| Employee Future Benefits | 18,441 | 17,039 | 13,920 |
| Other Company Fees | 2,944 | 2,296 | 3,379 |
| Other Operating Expenses | 28,162 | 27,979 | 26,870 |
| Transfers (GEC) | (2,955) | (2,847) | (2,781) |
| Transfers (CDM) | (5,488) | (4,017) | (2,533) |
| Other contract costs | - | - | 4,081 |
| Total Net Expenses | $ 78,690 | $ 80,472 | $ 82,588 |



The relationship of operating expenses to the sale of energy (expressed in kWh) from 2016 to 2018 is presented in the table below.

| | | Electricity Supply | | Customer Service | | General | | Total Gross Expenses | |
|---|---|---|---|---|---|---|---|---|---|
| Year | kWh sold (000's) | Cost (000's) | Cost per kWh | Cost (000's) | Cost per kWh | Cost (000's) | Cost per kWh | Cost (000's) | Cost per kWh |
| 2016 | 5,950,100 | $ 27,400 | $ 0.0046 | $ 17,663 | $ 0.0030 | $ 41,898 | $ 0.0070 | $ 86,961 | $ 0.0146 |
| 2017 | 5,922,200 | $ 29,352 | $ 0.0050 | $ 16,754 | $ 0.0028 | $ 40,889 | $ 0.0069 | $ 86,995 | $ 0.0147 |
| 2018 | 5,876,100 | $ 28,185 | $ 0.0048 | $ 16,429 | $ 0.0028 | $ 38,866 | $ 0.0066 | $ 83,480 | $ 0.0142 |




The table and graph show that total gross expenses per kWh have decreased by approximately 3.4% compared to 2017.

There were decreases in General Costs of $2.0 million, Customer Service Costs of $0.3 million and in Electricity Supply Costs of $1.2 million. Our observations and findings based on our detailed review of the individual significant expense categories variances are noted below.

## Salaries and Benefits (including executive salaries)

A detailed comparison of the number of full-time equivalent (FTE) employees by category for 2016 to 2018 (including 2018 plan) is as follows:

| | Actual 2018 | Plan 2018 | Actual 2017 | Actual 2016 | Actual - Plan | Actual 2018-2017 |
|---|---|---|---|---|---|---|
| Executive Group | 5.7 | 6.0 | 6.3 | 6.0 | (0.3) | (0.6) |
| Corporate Office | 19.8 | 19.8 | 20.0 | 20.7 | - | (0.2) |
| Finance | 91.6 | 92.6 | 88.9 | 89.5 | (1.0) | 2.7 |
| Egineering and Operations | 372.9 | 374.9 | 365.4 | 406.9 | (2.0) | 7.5 |
| Customer Relations | 78.8 | 83.5 | 84.3 | 62.8 | (4.7) | (5.5) |
| | 568.8 | 576.8 | 564.9 | 585.9 | (8.0) | 3.9 |
| Temporary employees | 50.4 | 39 | 46.3 | 48.6 | 11.4 | 4.1 |
| Total | 619.2 | 615.8 | 611.2 | 634.5 | 3.4 | 8.0 |

The overall number of FTE's in 2018 compared to 2017 increased by 8. The budgeted number of FTEs in the 2018 Plan was 615.8 versus actual of 619.2. The variances between 2018, 2018 Plan and 2017 are the result of the following:

- Finance and Information Technology is consistent with plan but higher than 2017 due to additional resources required to support increased regulatory proceedings, and the full year impact of 2017 hires and timing of replacement hires for retirements and leaves.
- Engineering and operations is lower than plan due to a shift in Engineering Technologists from regular to temporary employees and timing of replacement hires for retirements and leaves. The increase in 2018 over 2017 due to higher engineering support and increased labour required for construction and third party work for telecommunications companies.
- Customer relations is lower than plan and 2017 due to a shift to temporary labour for customer service representatives and customer energy conservation activity.
- Temporary Employees is higher than plan and 2017 due to increased customer service activity and a shift from regular to temporary employees for engineering and operations and customer relations. The increase in FTEs over 2017 is partially offset by a decrease in meter readers following completion of the automated meter reading strategy.

An analysis of salaries and wages by type of labour and by function from 2016 to 2018 is as follows:

| (000's) | **Actual 2018** | Actual 2017 | Actual 2016 | **Variance 2018-2017** |
|---|---|---|---|---|
| **Type** | | | | |
| Internal labour | **$ 65,090** | $ 64,399 | $ 63,608 | $ 691 |
| Overtime | **6,568** | 6,807 | 4,925 | (239) |
| | **71,658** | 71,206 | 68,533 | 452 |
| Contractors | **15,409** | 12,883 | 10,593 | 2,526 |
| | **$ 87,067** | $ 84,089 | $ 79,126 | $ 2,978 |
| Function | | | | |
| Operating | **$ 39,095** | $ 39,341 | $ 36,770 | $ (246) |
| Capital and miscellaneous | **47,972** | 44,748 | 42,356 | 3,224 |
| Total | **$ 87,067** | $ 84,089 | $ 79,126 | $ 2,978 |
| Year over year percentage change | 3.54% | 6.27% | -4.40% | |

Our review of salaries and benefits included an analysis of the year to year variances, consideration of trends in labour costs, and discussion of the significant variances with Company officials. As indicated in the above table, total labour costs for 2018 were $2,978,000 (3.54%) higher than 2017.

Internal labour costs in 2018 were higher than 2017 due to normal labour inflation and increased labour for capital distribution work and regulatory activity. This increase was partially offset by lower corporate costs and labour savings related to the completion of the automated meter reading strategy.

Contract labour for 2018 was higher than 2017 due to increased labour for transmission deficiencies, rebuilds and distribution work for reconstruction, and the Waterford River duct bank.

As part of our review we completed an analysis of the average salary per FTE, including and excluding executive compensation (base salary and short-term incentive). The results of our analysis for 2016 to 2018 are included in the table below:

**Salary Cost Per FTE**

| | **Actual 2018** | Actual 2017 | Actual 2016 | Variance 2018-2017 |
|---|---|---|---|---|
| Total reported internal labour costs | **$ 65,090** | $ 64,399 | $ 63,608 | $ 691 |
| Benefit costs (net) | **(8,939)** | (8,960) | (8,470) | 21 |
| Other adjustments | **(725)** | (1,171) | (772) | 446 |
| Base salary costs | **55,426** | **54,268** | 54,366 | 1,158 |
| Less: executive compensation | **(1,693)** | (2,016) | (1,864) | 323 |
| Base salary costs (excluding executive) | **$ 53,733** | $ 52,252 | $ 52,502 | $ 1,481 |
| FTE's (including executive members) | **619.2** | 611.2 | 634.5 | |
| FTE's (excluding executive members) | **615.5** | 606.9 | 630.5 | |
| Average salary per FTE | **89,512** | 88,789 | 85,683 | |
| % increase | **0.81%** | 3.62% | 1.42% | |
| Average salary per FTE (excluding executive members) | **87,300** | 86,097 | 83,271 | |
| % increase | **1.40%** | 3.39% | 1.17% | |

The above analysis indicates that the rate of increase in average salary per FTE for 2018 has decreased from 2017 and is more in line with 2016.

***Short Term Incentive (STI) Program***

The following table outlines the actual results for 2016 to 2018 and the targets set for 2018:

| Measure | Target 2018 | Actual 2018 | Actual 2017 | Actual 2016 |
|---|---|---|---|---|
| Controllable Operating Costs/Customer | **$222.00** | $225.10 | $228.80 | $219.70 |
| Earnings | **40.0m** | 41.2m | 41.0m | 40.0m |
| Reliability - Duration of Outages (SAIDI) | **2.27** | 2.65 | 2.28 | 2.24 |
| Customer Satisfaction - % Satisfied | **86.5%** | 85.6% | 86.5% | 86.1% |
| Customer Satisfaction - 1st Call Resolution | **-** | - | - | - |
| Injury Frequency Rate | **0.18** | 0 | 0.2 | 0.4 |
| Regulatory Performance | **Subjective** | 150% | 120% | 140% |

2018 STI results were adjusted to remove the impact of the loss of supply from Hydro and the impact of severe weather conditions in April and November. The Company indicated that Regulatory performance is evaluated on a subjective basis, as it is difficult to apply a statistical or a simple cost based analyses.

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.

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

The individual measures of performance for Directors are developed in consultation with the individuals and their respective executive member. Performance measures for the executive members, President and CEO are approved by the Board of Directors. Each measure is reflective of key projects or goals and focuses on departmental or divisional priorities.

The program operates to provide 100% payout of established STI pay if the Company meets, on average, 100% of its performance targets. The STI pay for 2018 is established as a percentage of base pay for the three employee groups. For 2018, measures relating to 'Earnings', ', 'Safety', and 'Regulatory Performance' metrics were met, however, 'Controllable Operating Costs/Customer', 'SAIDI' and 'Customer Satisfaction' metrics fell below target.

The following table illustrates the target as a percentage of base pay, together with the actual STI payouts for 2016 to 2018:

| | Target 2018 | Actual 2018 | Target 2017 | Actual 2017 | Target 2016 | Actual 2016 |
|---|---|---|---|---|---|---|
| President | 50% | 60.30% | 50% | 66.32% | 50% | 67.20% |
| Executive | 35% - 40% | 47.04% | 40% | 57.28% | 40% | 53.90% |
| Directors | 15% | 18.28% | 15% | 20.03% | 15% | 19.60% |

STI actual payout rates for 'President', 'Executive' and 'Director' employee groups are lower than the prior year and each payout rate exceeded targets consistent with 2017 and 2016.

In dollar terms, the STI payouts for 2016 to 2018 are as follows:

| | Actual 2018 | Actual 2017 | Actual 2016 | Variance 2018-2017 |
|---|---|---|---|---|
| President | **$ 230,000** | $ 240,396 | $ 242,000 | $ (10,396) |
| Executive | **346,000** | 506,604 | 442,000 | (160,604) |
| Directors | **296,200** | 332,999 | 323,300 | (36,799) |
| Total | **$ 872,200** | $ 1,079,999 | $ 1,007,300 | $ (207,799) |
| Year over Year % change | -19.24% | 7.22% | 3.82% | |

In accordance with Order No. P.U. 19 (2003) the Company has classified STI payouts in excess of 100% of target as a non-regulated expense. In accordance with Order No. P.U. 18 (2016) the Company has also classified STI payouts relating to half of the earnings and regulatory performance metrics as a non-regulated expense. In 2018, the non-regulated portion (before tax adjustment) was $262,753 (2017 - $301,080).

***Executive Compensation***

The following table provides a summary and comparison of executive compensation for 2016 to 2018.

| | Base Salary | Short Term Incentive | Other | Total |
|---|---|---|---|---|
| **2018** | | | | |
| Total executive group | $ 1,116,648 | $ 576,000 | $ 630,311 | $ 2,322,959 |
| **Average per executive (3.74)** | **$ 298,569** | **$ 154,011** | **$ 168,532** | **$ 621,112** |
| **2017** | | | | |
| Total executive group | $ 1,271,865 | $ 747,000 | $ 295,555 | $ 2,314,420 |
| **Average per executive (4.33)** | **$ 293,733** | **$ 172,517** | **$ 68,258** | **$ 534,508** |
| **2016** | | | | |
| Total executive group | $ 1,180,144 | $ 684,000 | $ 226,663 | $ 2,090,807 |
| **Average per executive (4)** | **$ 295,036** | **$ 171,000** | **$ 56,666** | **$ 522,702** |
| **% Average increase 2018 vs 2017** | -12.20% | -22.89% | 113.26% | 0.37% |
| **Per executive % average increase 2018 vs 2017** | 1.62% | -12.02% | 59.50% | 13.94% |

Base salary for the executive group in 2018 decreased from 2017 primarily due to the decrease in FTE for executives which in 2018 was 3.74 FTE compared 4.33 FTE for 2017. In 2018 the appointment of a new CEO was effective June 1, 2018; however, the new executive position of Vice President, Energy Supply and Planning was not effective until September 1, 2018, which resulted in a 2018 FTE of 3.74.

Other compensation for the executive group in 2018 increased from 2017, primarily due to a vacation payout for an executive and an increase in the performance share unit payout received by executives. STI payouts and performance share unit payouts were agreed to the Board of Directors' minutes.

## Company Pension Plan

For 2018, we reviewed the accounts supporting the gross charge of $7,726,000 of pension expense for the Company. A detailed comparison of the components of pension expense for 2016 to 2018.

| | Actual 2018 | Actual 2017 | Actual 2016 | Variance 2018-2017 |
|---|---|---|---|---|
| Pension expense per actuary | **$ 5,163,000** | $ 6,165,000 | $ 7,330,000 | $ (1,002,000) |
| Pension uniformity plan (PUP)/supplemental employee retirement program (SERP) | **501,000** | 571,000 | 557,000 | (70,000) |
| Group RRSP @ 1.5% | **289,000** | 321,000 | 350,000 | (32,000) |
| Individual RRSP's | **1,790,000** | 1,640,000 | 1,531,000 | 150,000 |
| Less: Refunds (net of other expenses) | **(17,000)** | (22,000) | (5,000) | 5,000 |
| Total | **$ 7,726,000** | $ 8,675,000 | $ 9,763,000 | $ (949,000) |
| Year over year percentage change | **(10.94%)** | (11.14%) | (44.85%) | |

Overall, pension expense for 2018 is lower than 2017 primarily due to the expiry of a transitional obligation regulatory amortization in 2017 and lower net pension expense driven by a higher expected return on plan assets and lower interest costs. This was partially offset by higher current service costs and higher amortization of net actuarial losses.

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 is allowed as reasonable, prudent and properly chargeable to the operating account of the Company. The PUP and SERP expenses decreased by 12.12% in 2018.

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 RRSP contributions increased by 8.38% as a result of the closure of the Company's Defined Benefit Plan in 2004. New hires are added to the Individual RRSP Plan whereas the majority of retirements and terminations are out of the Group RRSP Plan. The actual increase of approximately $118,000 in overall RRSP contributions (Group and Individuals) made by the employer in comparison to 2017 primarily reflects wage increases and new hires in the year, which was partially offset by retirements and terminations. The net increase for RRSP expenditures in 2018 is due to new hires in the 5.75% Plan who are replacing retired employees in the 1.5% Plan. Over the last few years, changes in the Company's workforce have resulted in a decrease in Group RRSP costs (as those individuals retire) and an increase in the individual RRSP (resulting from new hires).

## 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 2016 to 2018 are as follows:

| (000's) | Actual 2018 | Actual 2017 | Actual 2016 | Variance 2018-2017 |
|---|---|---|---|---|
| Accrued OPEBs | **$ 3,648** | $ 5,861 | $ 6,089 | $ (2,213) |
| Amortization of transitional balance | **3,504** | 3,504 | 3,504 | - |
| Amount capitalized | **(958)** | (1,001) | (915) | 43 |
| Total | **$ 6,194** | $ 8,364 | $ 8,678 | $ (2,170) |

According to the Company, the decrease in OPEBs expense from 2017 to 2018 is primarily due to a lower benefit obligation resulting from the 2017 OPEB valuation and the expiry of a regulatory amortization in August 2017.

## Intercompany Charges

Our review of intercompany charges included the following specific procedures:

- assessed the Company's compliance with P.U. 19 (2003), P.U. 32 (2007), P.U. 43 (2009), and P.U. 13 (2013);
- compared intercompany charges for the years 2017 to 2018 and investigated any unusual fluctuations;
- reviewed detailed listings of charges for 2018 and investigated any unusual items;
- vouched a sample of transactions for 2018 to supporting documentation;
- assessed the appropriateness of the amounts being charged; and,
- reviewed the methodology developed by Fortis Inc. in 2008 to allocate recoverable expenses to its subsidiaries.

The following table summarizes intercompany transactions from 2016 to 2018 for charges to and from Newfoundland Power Inc.:

| | Actual 2018 | Actual 2017 | Actual 2016 | Variance 2018-2017 |
|---|---|---|---|---|
| Charges from related companies | | | | |
| Regulated | **$ 1,121,634** | **$ 225,084** | $ 153,602 | $ 896,550 |
| Non-Regulated | **2,101,634** | **2,143,224** | 2,293,715 | (41,590) |
| Total | **$ 3,223,268** | **$ 2,368,308** | $ 2,447,317 | $ 854,960 |
| Charges to related companies | **$ 643,394** | **$ 2,206,966** | $ 329,339 | $ (1,563,572) |

Fortis bills its recoverable expenses on estimates rather than actual for the first three quarters of each year. For the fourth quarter, a true-up calculation is completed to reflect actual recoverable expenses incurred during the year. Recoverable expenses are allocated among the subsidiaries based on actual results.

The majority of the recoverable expenses from Fortis Inc. relate to non-regulated expenses.

We reviewed Fortis Inc.'s methodology to estimate its recoverable expenses and noted during our review that Fortis Inc. continues to allocate its recoverable costs based on its subsidiaries' assets. There were no significant changes to the methodology in 2018.

- Fortis Inc. estimated its net pool of operating expenses for 2018 based on the 2019-2023 business plan and is billed quarterly.
- On a quarterly basis, these expenses are subject to a true-up based on actual expenses incurred during the quarter with any true-up applied in the subsequent quarter.

During the fourth quarter of 2018, a "true-up" calculation was completed to reflect actual recoverable expenses which were determined to be $1,847,000 and are summarized as follows:

**2018 Recoverable Expenses from Fortis Inc.**

| | Amount | |
|---|---|---|
| Staffing and Staffing Related | $1,054,000 | Non-regulated |
| Director Fees and Travel | 139,000 | Non-regulated |
| Consulting and Legal fees | 180,000 | Non-regulated |
| Trustee Agent Fees | 25,000 | Regulated |
| Audit and Other Fees | 70,000 | Non-regulated |
| 2017 Recovery True Up | 20,000 | Non-regulated |
| Annual Meeting Expenses | 44,000 | Non-regulated |
| Insurance (D&O) | 43,000 | Non-regulated |
| Other Costs | 272,000 | Non-regulated |
| | 1,847,000 | |
| Less amounts previously billed: | | |
| Q1 2018 | 670,000 | |
| Q2 2018 | 427,000 | |
| Q3 2018 | 291,000 | |
| Q4 2018 balance owing | $ 459,000 | |

As detailed above, trustee agent fees for $25,000 were the only expenses allocated to regulated operations by the Company relating to recoverable expenses. According to the Company, regulated charges from Fortis Inc. to Newfoundland Power are generally not based on specific allocation percentages rather charges are invoiced based on actual costs or based on Newfoundland Power's usage of a specific service. These are detailed in the analysis below of regulated and non-regulated operations.

The analysis below is a review of the intercompany variances related to charges to and from Fortis Inc. as well as other related parties. The following table summarizes the various components of the regulated intercompany transactions for 2016 to 2018 with Fortis Inc.:

| (Regulated) | Actual 2018 | Actual 2017 | Actual 2016 | Variance 2018-2017 |
|---|---|---|---|---|
| **Charges from Fortis Inc.** | | | | |
| Trustee fees and share plan costs | **$ 25,000** | **$ 26,000** | $ 33,000 | $ (1,000) |
| Miscellaneous | **941,488** | **133,361** | 53,059 | 808,127 |
| Staff Charges | **92,711** | **-** | - | 92,711 |
| | **$ 1,059,199** | **$ 159,361** | $ 86,059 | $ 899,838 |
| Year over year percentage change | **564.65%** | **85.18%** | 8.62% | |
| **Charges to Fortis Inc.** | | | | |
| Postage and couriers | **$ 3,165** | **$ 4,113** | $ 7,583 | $ (948) |
| Staff charges | **27,471** | **43,581** | 38,282 | (16,110) |
| Staff charges - insurance | **-** | **-** | 550 | - |
| IS Charges | **-** | **5,888** | - | (5,888) |
| Pole removal and installation | **-** | **93** | 138 | (93) |
| Miscellaneous | **97,880** | **49,406** | 16,895 | 48,474 |
| | **$ 128,516** | **$ 103,081** | $ 63,448 | $ 25,435 |
| Year over year percentage change | **24.67%** | 62.47% | (19.26%) | |

The most significant fluctuations from our analysis of regulated charges from Fortis Inc. is an increase in the miscellaneous account and staff charges of $808,127 and $92,711, respectively. These fluctuations are primarily due to the pay out of SERP costs of $817,115 for a former CEO who retired January 1, 2018 and an employee on secondment from Fortis Inc., respectively.

The following table provides a summary and comparison of the non-regulated intercompany transactions for 2016 to 2018:

| (Non-Regulated) | Actual 2018 | Actual 2017 | Actual 2016 | Variance 2018-2017 |
|---|---|---|---|---|
| **Charges from Fortis Inc.** | | | | |
| Director's fees and travel | **139,000** | **202,000** | 231,000 | (63,000) |
| Staff charges | **1,054,000** | **1,204,000** | 1,293,000 | (150,000) |
| Miscellaneous | **908,634** | **732,811** | 769,715 | 175,823 |
| | **$ 2,101,634** | **$ 2,138,811** | $ 2,293,715 | $ (37,177) |
| **Charges from Maritime Electric** | | | | |
| Miscellaneous | **$ -** | **$ 4,413** | $ - | (4,413) |
| | **$ 2,101,634** | **$ 2,143,224** | $ 2,293,715 | $ (41,590) |

Director's fees and travel, and staff charges decreased by $63,000 and $150,000 respectively, primarily due to an allocation reduction based on the Company's percentage of Fortis Inc.'s assets.

Miscellaneous charges increased by $175,823 primarily due to an increase in performance share units and restricted share units paid.

The following table provides a summary and comparison of the other intercompany transactions for 2016 to 2018:

| Intercompany Transactions (Other) | Actual 2018 | Actual 2017 | Actual 2016 | Variance 2018-2017 |
|---|---|---|---|---|
| **Charges to Fortis Properties** | | | | |
| Staff charges - insurance | $ - | $ - | $ 2,950 | $ - |
| **Charges to Fortis Ontario Inc.** | | | | |
| Staff charges | $ 371,640 | $ 138,200 | $ 22,698 | $ 233,440 |
| Staff charges - insurance | - | - | 1,794 | - |
| Miscellaneous | 35,193 | 1,703 | 400 | 33,490 |
| | $ 406,833 | $ 139,903 | $ 24,892 | $ 266,930 |
| **Charges to Maritime Electric** | | | | |
| Staff charges | $ - | $ 3,719 | $ 34,749 | $ (3,719) |
| Staff charges - insurance | - | - | 756 | - |
| Miscellaneous | 550 | 550 | 530 | - |
| | $ 550 | $ 4,269 | $ 36,035 | $ (3,719) |
| **Charges from Maritime Electric** | | | | |
| Miscellaneous | $ 15,258 | $ 16,713 | $ 2,880 | $ (1,455) |
| **Charges from Central Hudson Gas & Electric** | | | | |
| Miscellaneous | $ 5,705 | $ 8,034 | $ 3,538 | $ (2,329) |
| **Charges to Belize Electric Company Ltd.** | | | | |
| Staff charges | $ 91,553 | $ 112,387 | $ 121,021 | $ (20,834) |
| Miscellaneous | - | 845 | 1,793 | (845) |
| | $ 91,553 | $ 113,232 | $ 122,814 | $ (21,679) |
| **Charges to FortisAlberta Inc.** | | | | |
| Miscellaneous | $ 4,980 | $ 4,740 | $ 4,510 | $ 240 |
| **Charges from FortisAlberta Inc.** | | | | |
| Miscellaneous | $ 38,073 | $ 37,611 | $ 44,744 | $ 462 |

| Intercompany Transactions (Other) Cont'd. | Actual 2018 | Actual 2017 | Actual 2016 | Variance 2018-2017 |
|---|---|---|---|---|
| **Charges to FortisBC Inc./ Fortis BC Holdings** | | | | |
| Staff Charges | $ - | $ 11,578 | $ - | $ (11,578) |
| IS charges | - | - | - | - |
| Miscellaneous | 9,370 | 9,310 | 9,240 | 60 |
| | $ 9,370 | $ 20,888 | $ 9,240 | $ (11,518) |
| **Charges from FortisBC Inc./ FortisBC Holdings** | | | | |
| Miscellaneous | $ 3,399 | $ 3,365 | $ 7,359 | $ 34 |
| **Charges to Caribbean Utilities Co. Limited** | | | | |
| Staff charges | $ - | $ 4,240 | $ 30,111 | $ (4,240) |
| **Charges from Caribbean Utilities Co. Limited** | | | | |
| Miscellaneous | $ - | $ - | $ 9,022 | $ - |
| **Charges to Fortis Turks and Caicos** | | | | |
| Staff charges | $ - | $ 698,896 | $ 32,289 | $ (698,896) |
| Miscellaneous | 1,592 | 1,117,717 | 3,050 | (1,116,125) |
| | $ 1,592 | $ 1,816,613 | $ 35,339 | $ (1,815,021) |

The most significant fluctuations from our analysis of other intercompany charges for 2018 compared to 2017 are as follows:

- Staff charges to Fortis Ontario Inc. increased by $233,440 primarily due to an employee on secondment to Wataynikaneyap Power from engineering.
- Staff charges and miscellaneous charges to Fortis Turks and Caicos have decreased by $698,896 and $1,116,125 respectively as the 2017 year included charges relating to hurricane Irma. Current year staff charges are more in line with 2016.

The Company did not enter into any short-term loan agreements with related parties during the year.

**As a result of completing our procedures in this area, nothing came to our attention that would lead us to believe that intercompany charges are unreasonable.**

### *Other Company Fees and Deferred Regulatory Costs*

The procedures performed for this category included a review of the transactions for 2018 and vouching of a sample of individual transactions to supporting documentation.

| (000's) | | Actual 2018 | | Actual 2017 | | Actual 2016 | | Variance 2018-2017 |
|---|---|---|---|---|---|---|---|---|
| **Other company fees** | | | | | | | | |
| Other company fees | $ | 2,855 | $ | 3,082 | $ | 2,092 | $ | (227) |
| Regulatory hearing costs | | 524 | | (786) | | 852 | | 1,310 |
| | $ | 3,379 | $ | 2,296 | $ | 2,944 | $ | 1,083 |
| Year over year percentage change | | 47.2% | | -22.0% | | 6.8% | | |
| **Deferred regulatory costs** | | | | | | | | |
| Total deferred regulatory costs | $ | 341 | $ | 341 | $ | 172 | $ | - |
| Year over year percentage change | | 0.0% | | 98.3% | | -46.6% | | |

Other Company Fee costs for 2018 were higher than 2017. According to the Company, this is primarily due to the lower costs in 2017 relating to the reduction in estimated liability of 3rd party costs associated with a PUB investigation into power outages and supply issues from 2014. Deferred regulatory costs are discussed in the section of the report relating to regulatory assets and liabilities.

**As noted in prior annual reviews, this category of costs often experiences significant fluctuations from year to year. In addition, the costs in this category generally relate to projects which are often non-recurring by nature. Consequently, we continue to recommend that this category be monitored closely on an annual basis.**

***Miscellaneous***

The breakdown of items included in the miscellaneous expense category for 2016 to 2018 is as follows:

| (000's) | Actual 2018 | Actual 2017 | Actual 2016 | Variance 2018-2017 |
|---|---|---|---|---|
| Miscellaneous | **$ 994** | **$ 1,117** | $ 1,082 | $ (123) |
| Cafeteria and lunchroom Supplies | **77** | **84** | 89 | (7) |
| Promotional items | **137** | **199** | 193 | (62) |
| Computer Software | **10** | **2** | 1 | 8 |
| Damage claims | **174** | **216** | 196 | (42) |
| Community relations activities | **2** | **3** | 3 | - 1 |
| Donations and charitable advertising | **183** | **217** | 202 | (34) |
| Books, magazines and subscriptions | **7** | **7** | 21 | - |
| Misc. lease payments | **35** | **34** | 34 | 1 |
| Total miscellaneous expenses | **$ 1,619** | $ 1,879 | $ 1,821 | $ (260) |
| Year over year percentage change | **-13.84%** | 3.19% | 3.17% | |

Miscellaneous expenses by their very nature can fluctuate from year to year. From 2017 to 2018 these expenses have decreased by 13.84% overall. According to the Company, miscellaneous costs for 2018 were lower than 2017 due to reduced damage claims, and lower costs for promotional items and miscellaneous supplies for customer energy conservation outreach activities.

**Our procedures in this expense category for 2018 included vouching a sample of transactions within the “miscellaneous category” to supporting documentation. Based upon the results of our procedures nothing has come to our attention to indicate that the 2018 expenses are unreasonable.**

***Conservation and Demand Management (CDM)***

In compliance with Order No. P.U. 7 (1996-97), the Company filed the 2018 Conservation and Demand Management Report with the Board. This report provided a summary of 2018 CDM activities and costs as well as the outlook for 2019.

In 2015, Newfoundland and Labrador Hydro and the Company ("the Utilities") also finalized the joint Five-Year Conservation Plan: 2016-2020 (the "2016 Plan") which builds on the Utilities' experience and continues to reflect the principles underlying two previous joint, multi-year conservation plans. It reflects refinement of the opportunities identified in the Conservation Potential Study through in-depth local market research and program cost benefit analysis.

In 2018, the Utilities continued to implement the 2016 Plan. These activities relate to the expansion of the commercial program; completion of the commercial end use survey; continued initiatives to education customers about heat pumps; and, continuation of takeCHARGE's partnership with the Government of Newfoundland and Labrador to offer the Energy Efficiency Loan Program.

Total CDM costs in 2018 totaled $7,252,000 compared to $7,865,000 in 2017, a $613,000 decrease. Conservation costs are lower than in 2017 due to variations in program participation that resulted in higher energy savings but lower incentive payouts.

In 2018, $6,239,000 ($4,367,000 after tax) in CDM costs were deferred to be amortized over 7 years as per Order No. P.U. 13 (2013).

***Based upon the results of our procedures we concluded that CDM is in compliance with Board Orders.***

### *Other Operating and General Expense Categories*

In addition to the various categories of expenses commented on above, the other categories of operating and general expenses by breakdown were also analyzed for any unusual variances between 2018 and 2017.

| (000's) | Actual 2018 | Actual 2017 | Actual 2016 | Variance 2018-2017 |
|---|---|---|---|---|
| Vehicle expense | 1,682 | 1,854 | 1,797 | (172) |
| Operating materials | 1,511 | 1,528 | 1,425 | (17) |
| Inter-company charges | 1,847 | 2,002 | 2,145 | (155) |
| Plants, Subs, System Oper & Bldgs | 2,812 | 2,796 | 2,770 | 16 |
| Travel | 1,127 | 1,235 | 1,160 | (108) |
| Tools and clothing allowance | 1,254 | 1,234 | 1,161 | 20 |
| Conservation | 2,732 | 2,981 | 4,253 | (249) |
| Taxes and assessments | 1,286 | 1,252 | 1,214 | 34 |
| Uncollectible bills | 1,490 | 1,386 | 1,194 | 104 |
| Insurance | 1,306 | 1,326 | 1,293 | (20) |
| Severance & other employee costs | 68 | 102 | 47 | (34) |
| Education, training, employee fees | 403 | 339 | 275 | 64 |
| Trustee and directors' fees | 481 | 489 | 471 | (8) |
| Stationary & copying | 224 | 214 | 266 | 10 |
| Equipment rental/maintenance | 784 | 806 | 838 | (22) |
| Communications | 2,822 | 2,927 | 2,959 | (105) |
| Advertising | 1,443 | 1,592 | 1,519 | (149) |
| Vegetation management | 1,692 | 2,099 | 1,820 | (407) |
| Computing equipment & software | 1,628 | 1,451 | 1,359 | 177 |
| Transfers (GEC) | (2,781) | (2,847) | (2,955) | 66 |
| CDM amortization | 3,706 | 2,741 | 1,712 | 965 |

From this analysis and from explanations provided by the Company, the following observations were made with respect to the more significant fluctuations:

- Vehicle expenses in 2018 were lower than 2017 due to reduced operating work associated with automated meter reading.
- Inter-company Charges for 2018 were lower than 2017 due to lower recoveries charged by Fortis.
- Conservation costs in 2018 were lower than 2017 as a result of variations in conservation program participation.
- Advertising costs in 2018 were lower than 2017 due to lower marketing and advertising requirements for customer energy conservation programs.
- Vegetation management costs for 2018 were lower than 2017 due to lower vegetation management costs for transmission.
- Computing equipment & software costs for 2018 were higher than 2017 due to higher third party software licensing costs.
- Amortization of Deferred CDM costs commenced in 2014 and is higher in 2018 due to the inclusion of the fifth year of deferred customer energy conservation programming costs.

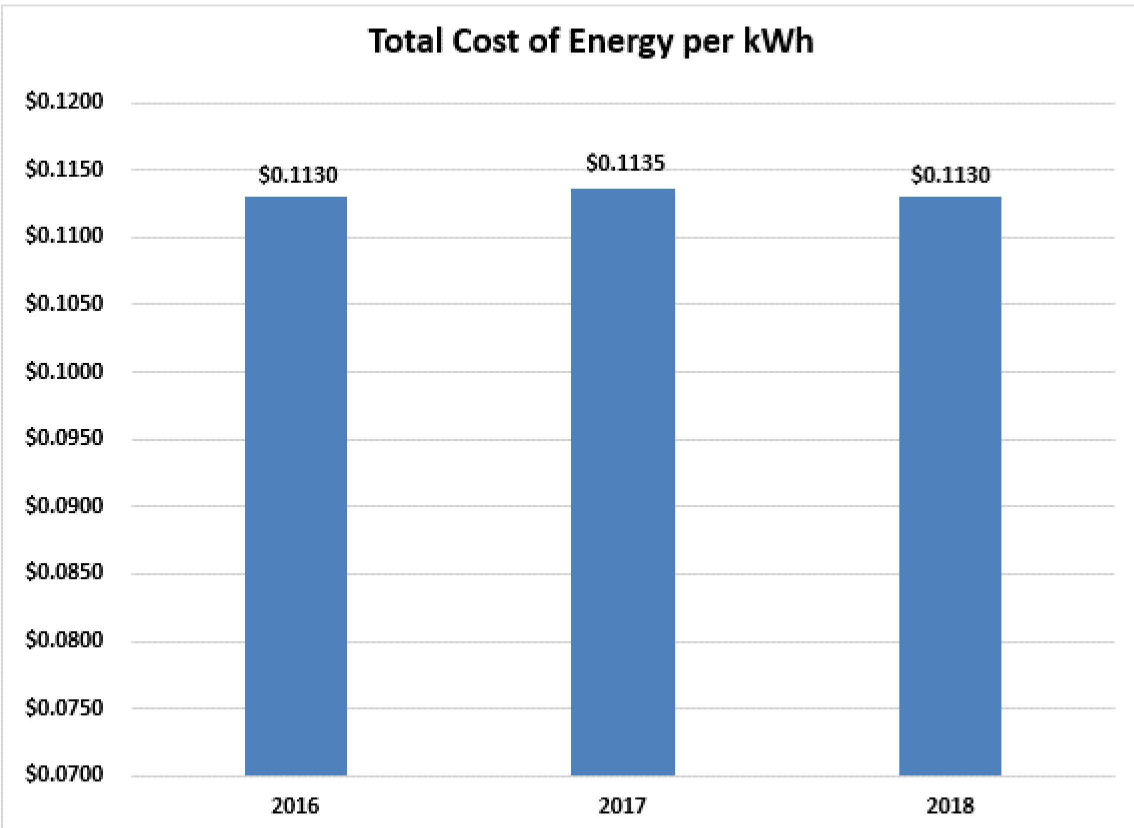
## Other Costs

***Scope:*** ***Conduct an examination of purchased power, depreciation, interest and income taxes to assess their reasonableness and prudence in relation to sales of power and energy and their compliance with Board Orders.***

The following table and graph provide the total cost of energy (expressed in kWh) from 2016 to 2018:

000's

| Year | kWh sold (000's) | Operating Expenses | Purchased Power | Deferred Cost Recoveries and Amortizations | Depreciation | Finance Charges | Income Taxes | Net Earnings | Total Cost of Energy | Cost per kWh |
|---|---|---|---|---|---|---|---|---|---|---|
| 2016 | 5,950,100 | $ 78,690 | $ 443,311 | $ 2,064 | $ 60,472 | $ 35,235 | $ 11,851 | $ 40,508 | $ 672,131 | $ 0.1130 |
| 2017 | 5,922,200 | $ 80,472 | $ 440,249 | $ (1,032) | $ 62,973 | $ 35,365 | $ 12,882 | $ 41,526 | $ 672,435 | $ 0.1135 |
| 2018 | 5,876,100 | $ 82,588 | $ 427,219 | $ (1,032) | $ 65,170 | $ 36,212 | $ 12,280 | $ 41,744 | $ 664,181 | $ 0.1130 |



***Purchased Power***

We have reviewed the Company's purchased power expense for 2018 and have investigated the reasons for any fluctuations and changes. We performed a recalculation of the purchased power to ensure that the cost per kilowatt-hour charged by Newfoundland and Labrador Hydro is consistent with the established rates provided and found no errors.

Purchased power expense decreased by $13.0 million, from $440.2 million in 2017 to $427.2 million in 2018. According to the Company, the decrease in costs were lower in 2018 due to lower energy purchases, a 1.2% decrease in the wholesale electricity rate effective July 1, 2017, and lower demand charges.

***Depreciation***

We have reviewed the Company's rates of depreciation and assessed its compliance with the Gannett Fleming Depreciation Study based on plant in service as of December 31, 2014 and assessed the reasonableness of depreciation expense.

In Order No. P.U. 13 (2013) the Board ordered the Company to file a new depreciation study related to plant in service as of December 31, 2014. The study for plant in service as of December 31, 2014 was completed in 2015. The study was included in the 2016-2017 General Rate Application by the Company and was approved in Order No. P.U. 18 (2016), including the approval of the accumulated depreciation reserve variance to be amortized over the average remaining service life of the related assets. The depreciation rates from the 2014 depreciation study, including the amortization of the accumulated depreciation reserve, were implemented effective January 1, 2016. Gannett Fleming has recommended the continued use of the straight line equal life group ("ELG") method in its 2014 depreciation study.

The objective of our procedures in this section was to ensure that the 2018 depreciation amounts and rates are in compliance with Board Orders, and in agreement with the recommendations of the 2014 Depreciation Study undertaken by Gannett Fleming, Inc.

The specific procedures which we performed on the Company's depreciation expense included the following:

- agreed all depreciation rates to those recommended in the depreciation study;
- recalculated the Company's depreciation expense for 2018; and,
- assessed the overall reasonableness of the depreciation for 2018.

Amortization expense for 2018 is $65,170,000 as compared to $62,973,000 for 2017, representing a 3.5% increase. The 2018 and 2017 depreciation expense excludes the impact of the income tax deduction resulting from the cost of the removal of property, plant and equipment. The following table reconciles the depreciation as reported in the financial statements and the depreciation of fixed assets:

| ($000's) | 2018 | 2017 | Variance 2018-2017 | % |
|---|---|---|---|---|
| Depreciation and amortization as reported | $ 65,170 | $ 62,973 | $ 2,197 | **3.5%** |
| Less: Tax on Cost of Removal (1) | (5,704) | (5,486) | (218) | **4.0%** |
| Depreciation of Fixed Assets | $ 59,466 | $ 57,487 | $ 1,979 | **3.4%** |

Note 1: Recognized as a reduction in income tax for financial reporting purposes

The following table provides a comparison of the depreciation of fixed assets for 2018, 2017 and 2016:

| ($000's) | 2018 | 2017 | 2016 | Variance 2018-2017 | Variance 2017-2016 |
|---|---|---|---|---|---|
| Depreciation of Fixed Assets | $ 59,466 | $ 57,487 | $ 55,190 | $ 1,979 | $ 2,297 |

Depreciation of fixed assets for 2018 is $59,466,000 as compared to $57,487,000 for 2017, representing a 3.4% increase. The change is attributable to an increase of depreciable assets by approximately $59,714,000.

**Based on our review of depreciation expense, we conclude that the Company is in compliance with Order No. P.U. 19 (2003), Order No. P.U. 39 (2006), Order No. P.U. 32 (2007), Order No. P.U. 13 (2013), and Order No. P.U. 18 (2016). The recommendations and results of the Gannett Fleming Depreciation Study reported on the plant in service as of December 31, 2014 have been incorporated into the Company's depreciation calculations for 2018.**

***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 expense for the years 2016 to 2018:

| (000's) | Actual 2018 | Actual 2017 | Actual 2016 | Variance 2018-2017 |
|---|---|---|---|---|
| **Interest** | | | | |
| Long-term debt | **$ 35,788** | $ 35,013 | $ 34,846 | $ 775 |
| Other | **696** | 672 | 878 | 24 |
| **Amortization** | | | | |
| Debt discount | **235** | 234 | 223 | 1 |
| **Interest charged to construction** | **(523)** | (554) | (712) | 31 |
| Total Finance charges | **$ 36,196** | $ 35,365 | $ 35,235 | $ 831 |
| Year over year percentage change | **2.35%** | 0.37% | (1.37%) | |

In the above table, finance charges increased by approximately $0.83 million, from $35.4 million in 2017 to $36.2 million in 2018. According to the Company, the increase was due to higher long-term debt and related interest charges associated with continued investment in the electricity system.

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

***Income Tax Expense***

We have reviewed the Company's income tax expense for 2018 and have noted that the effective income tax rate decreased from 23.7% in 2017 to 22.7% in 2018. 2018 and 2017 results in the following effective rates:

| | 2018 | 2017 | 2016 | 2018-2017 |
|---|---|---|---|---|
| Income tax expense | $ 12,280 | $ 12,882 | $ 11,851 | $ (602) |
| Earnings before income tax | $ 54,024 | $ 54,408 | $ 52,359 | $ (384) |
| Effective income tax rate | 22.7% | 23.7% | 22.6% | -1.0% |

Income tax expense decreased by $602,000 compared to 2017. The statutory tax rate was 30.0% for both 2018 and 2017.

**Based upon our review of the Company's calculations, and considering the impact of timing differences, nothing has come to our attention to indicate that income tax expense for 2018 is unreasonable.**

***Costs Associated with Curtailable Rates***

In Order No. P.U. 7 (1996-97), the Board ordered that beginning January 1, 1997; all costs associated with curtailable rates shall be charged to regulated expenses, and not to the Rate Stabilization Account. The Board ordered that the demand credit for curtailment continue at $29/kVA until April 30, 1998. In Order No. P.U. 30 (1998-99), the Board ordered that this rate be extended until a review of the curtailment service option is presented at a public hearing. In Order No. P.U. 19 (2003) the Board accepted the recommendations of the parties, as set out in the Mediation Report, that the use of the Curtailable Service Option Credit of $29/kVA be retained as is until a change in Hydro's wholesale rates causes the matter to be reconsidered.

The total curtailment credits of $378,633 for the current period compare to a total of $424,674 for the same period during the previous year. The credit total for the 2017-2018 winter season is lower than the previous season total primarily due to lower contracted load curtailment. There were 22 option participants in 2017-2018, compared to 23 participants in the previous year. According to the Company, changes to the Curtailment credits year over year is due to variation in demand and consumption, and the mix of option participants achieving full or partial credit.

**Nothing has come to our attention to indicate that the Company is not in compliance with the applicable orders of Order No. P.U. 7 (1996-97) and Order No. P.U. 30 (1998-99).**

## Non-Regulated Expenses

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

- assessed the Company's compliance with Board Orders;
- compared non-regulated expenses for 2018 to prior years and investigated any unusual fluctuations;
- reviewed detailed listings of expenses for 2018 and investigated any unusual items; and
- assessed the reasonableness and appropriateness of the amounts being charged.

In the calculation of rates of return the following items are classified as non-regulated:

| | Actual 2018 | Actual 2017 | Actual 2016 | | Variance 2018-2017 |
|---|---|---|---|---|---|
| Charged from Fortis Companies | **$ 1,904,428** | $ 2,121,500 | $ 2,249,100 | | $ (217,072) |
| Performance and restricted share units | **346,789** | 687,500 | 454,500 | | (340,711) |
| Donations and charitable advertising | **295,769** | 301,700 | 283,300 | | (5,931) |
| Executive short term incentive | **514,004** | 361,900 | 341,000 | | 152,104 |
| Miscellaneous | **61,088** | 45,000 | 70,200 | | 16,088 |
| | **3,122,078** | 3,517,600 | 3,398,100 | - | (395,522) |
| Less: Income Taxes | **936,623** | 1,055,300 | 1,019,400 | | (118,677) |
| Total non-regulated (net of tax) | **$ 2,185,455** | **$ 2,462,300** | **$ 2,378,700** | | $ (276,845) |

The Company has classified STI payouts in excess of 100% of target payouts and 50% portion of the earnings and regulatory performance metrics as non-regulated expenses in compliance with Order No. P.U. 19 (2003) and Order No. P.U. 18 (2016), respectively. For 2018 this represents an addition to non-regulated expenses (before tax adjustment) of $514,004 (2017 - $361,900). Details on the short-term incentive payouts are included in this report under the heading Short Term Incentive (STI) Program.

The income tax rate used by the Company for calculating total non-regulated expenses net of tax is 30.0% which agrees with the Company's statutory rate as identified in the 2018 annual report.

**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.**

## Regulatory Assets and Liabilities

***Scope:*** ***Conduct an examination of the changes to regulatory assets and liabilities***

***Regulatory Assets and Liabilities***

The following table summarizes Regulatory Assets and Regulatory Liabilities for 2017 and 2018:

| (000's) | 2018 Actual | 2017 Actual | Variance 2018-2017 |
|---|---|---|---|
| **Regulatory Assets** | | | |
| Rate stabilization account | **$ 1,607** | **$ 4,519** | $ (2,912) |
| OPEBs asset | **24,528** | **28,032** | (3,504) |
| Deferred GRA costs | **-** | **341** | (341) |
| Conservation and demand management deferral | **22,549** | **20,017** | 2,532 |
| Demand management incentive | **-** | **2,128** | (2,128) |
| Employee future benefits | **82,556** | **82,732** | (176) |
| Weather normalization account | **2,168** | **6,815** | (4,647) |
| Deferred income taxes | **212,900** | **207,207** | 5,693 |
| | **$346,308** | **$351,791** | $ (5,483) |
| **Regulatory Liabilities** | | | |
| Rate stabilization account | **$ 3,979** | **$ 4,254** | (275) |
| Cost recovery deferral | **-** | **1,032** | (1,032) |
| Future removal and site restoration provision | **160,047** | **151,975** | 8,072 |
| | **$164,026** | **$157,261** | $ 6,765 |

**<u>Rate Stabilization Account</u>**

The Rate Stabilization Account ("RSA") primarily relates to changes in the cost and quantity of fuel used by Hydro to produce electricity sold to the Company. On July 1st of each year customer rates are recalculated in order to amortize the balance in the RSA as of March 31st over the subsequent 12 month period. The rates for July 1, 2018 were approved by the Board in Order No. P.U. 41 (2017).

As of December 31, 2018, there was a charge to the RSA of $4,486,112 related to the Energy Supply Cost Variance Reserve in accordance with Order No. P.U. 32 (2007) and Order No. P.U. 43 (2009), and the Wholesale Rate Change Flow-Through Account approved in Order No. P.U. 20 (2018).

Pursuant to Order No. P.U. 31 (2010) the Board approved the Company's proposal to create an Other Post-Employment Benefits Cost Variance Deferral Account (OPEBVDA) as of January 1, 2011. This account consists of the difference between the actual other post-employment benefit expense for any year from that approved for the establishment of revenue requirement from rates. The balance in this account will be transferred to the RSA on March 31 in the year in which the difference arises. As of March 31, 2018, the credit balance of $2,053,764 in the OPEBVDA account was transferred to the RSA.

Pursuant to Order No. P.U. 43 (2009) the Board approved the Company's proposal to create a Pension Expense Variance Deferral Account (PEVDA) as of January 1, 2010. This account consists of the difference between the actual pension expense in accordance with accounting standards and the annual pension expense approved for rate setting purposes. The Company will charge or credit any amount in this account to the RSA as of March 31 in the year in which the difference relates. As of March 31, 2018, the balance of $273,942 in the PEVDA account was credited to the RSA.

Pursuant to Order No. P.U. 13 (2013) the Board approved the Company's proposal to transfer the annual balance accrued in the Weather Normalization Reserve account in the previous year to the RSA account on March 31 of the subsequent year and approved the deferral and amortization of annual conservation program costs over seven years with recovery through the Rate Stabilization Account. As of March 31, 2018, $6,815,472 and $3,706,022 were credited to the RSA for the Weather Normalization Reserve account and for the amortization of deferred customer energy conservation program costs, respectively in accordance with Order No. P.U. 13 (2013).

The RSA is also adjusted for the Demand Management Incentive Account ($Nil balance in 2017 therefore no impact on RSA in 2018) and the amortization of deferred customer energy conservation program costs as approved by the Board.

**Other Post-Employment Benefits**

The Other Post-Employment Benefits ("OPEB") asset represents the cumulative difference between the OPEB expense recognized by the Company based on the cash basis and the OPEB expense based on accrual accounting required under accounting standards. In Order No. P.U. 43 (2009) the Board ordered that the Company file a comprehensive proposal for the adoption of the accrual method of accounting for OPEB costs as of January 1, 2011. The report was filed by Newfoundland Power on June 30, 2010. In summary, the Board ordered the approval, for regulatory purposes, of the accrual method of accounting for OPEBs costs and income tax related to OPEBs; recovery of the transitional balance, or regulatory asset, of $52.4 million as at January 1, 2011, over a 15-year period; and adoption of the OPEB Cost Variance Deferral Account. These recommendations were approved by the Board in Order No. P.U. 31(2010).

**Deferred general rate application costs**

In Order No. P.U. 18 (2016) the Board approved the deferral of cost related to 2016/2017 GRA as well as amortization of this deferral over a 30 month period commencing on July 1, 2016. Actual costs incurred and deferred were approximately $854,000 with amortization of $341,000 incurred in 2018.

**Conservation and Demand Management Deferral**

The Conservation and Demand Management deferral account arose as a result of the Company's implementation of conservation and demand management programs. These costs totaled $1,357,000 (before tax) and the Board ordered pursuant to Order No. P.U. 13 (2009) that these costs be deferred until a further Order of the Board. In Order No. P.U.43 (2009), the Board approved the Company's proposal to recover the 2009 conservation programming costs over the remaining four years of the five year Energy Conservation Plan through the Conversation Cost Deferral Account. Amortization of this account commenced in 2010.

Pursuant to Order No. P.U. 13 (2013) the Board approved the Company's proposed change in definition of conservation program costs and the deferral and amortization of annual conservation program costs over seven years with recovery through the Rate Stabilization Account. The actual costs incurred and deferred at December 31, 2018 were $22,549,000 with amortization of $3,706,022 in 2018.

**Employee future benefits**

On November 10, 2011, the Company submitted an application to the Board requesting approval for the January 1, 2012 adoption of US GAAP for regulatory purposes. On December 15, 2011 pursuant to Order No. P.U. 27 (2011) the Board approved the Company's adoption of US GAAP for general regulatory purposes.

Upon transition from Canadian GAAP to U.S. GAAP, there were several one-time adjustments with respect to the accounting for employee future benefits, as follows:

- The unamortized balances for transitional obligations associated with defined benefit pension plans, and the majority of the unamortized transitional obligation for OPEBs were required to be recorded as a reduction to retained earnings. The Board ordered that these balances be recorded as a regulatory asset to be amortized through 2017 as an increase to employee future benefits expense.
- The unamortized balances related to past service costs, actuarial gains or losses, and a portion of the unamortized transitional obligation for OPEBs were required to be recorded as a reduction to equity and classified as accumulated other comprehensive loss on the balance sheet. The Board ordered that these balances be reclassified as a regulatory asset. The amortization of these balances will continue to be included in the calculation of employee future benefit expense.
- The period over which pension expense is recognized differed between Canadian GAAP and U.S. GAAP. Therefore, the cumulative difference was recorded as a regulatory asset to be recovered from customers in future rates. The disposition of balances in this account will be determined by a further order of the Board.

In Order No. P.U. 27 (2011) the Board ordered that Newfoundland Power "*apply to the Board for approval of changes to existing regulatory assets and liabilities and the creation of any new regulatory assets and liabilities, along with appropriate definitions of the accounts related to these regulatory assets and liabilities, that will be required to effect the adoption of US GAAP".*

On April 9, 2012, the Company submitted an application to the Board requesting specific approval of the following:

i. Opening balances for regulatory assets and liabilities of $131,249,000 (comprising the Defined Benefit Pension Plan regulatory asset of $109,197,000, OPEBs Plan regulatory asset of $21,116,000 and the PUP regulatory asset of $936,000) associated with employee future benefits which arise upon Newfoundland Power's adoption of US GAAP effective January 1, 2012; and,
ii. a definition of the account related to those regulatory assets and liabilities.

In Order No. P.U. 11 (2012) the Board approved the creation of a regulatory asset of $131.2 million, rather than a reduction in the Company's equity, to reflect the accumulated difference to January 1, 2012 in defined benefit pension expense calculated under U.S. GAAP and Canadian Generally Accepted Accounting Principles.

The period over which pension expense had been recognized differed between that used for regulatory purposes and U.S. GAAP. In Order No. P.U. 13 (2013) the Board approved that pension expense for regulatory purposes be recognized in accordance with U.S. GAAP effective January 1, 2013 and that the accumulated difference in pension expense to December 31, 2012 of $12,400,000 be amortized evenly over 15 years to pension expense.

As of December 31, 2018, the regulated asset for employee future benefits was $82,556,000.

**Weather Normalization Account**

The Weather Normalization reserve reduces earnings volatility by adjusting purchased power expense and electricity sales revenue to eliminate variances in purchases and sales caused by the difference between normal and actual weather conditions.

Commencing in 2013, Order No. P.U. 13 (2013) approved the disposition of the balance accrued in the Weather Normalization Account in the previous year to the Rate Stabilization Account at March 31 of the following year. In Order No. P.U. 13 (2019) the Board approved the December 31, 2018 net regulatory asset balance in the Weather Normalization Account of $2,168,000 ($1,517,324 net of future income tax).

**Deferred income taxes**

Deferred income tax assets and liabilities associated with certain temporary timing differences between the tax basis of assets and the liabilities carrying amount are not included in customer rates. These amounts are expected to be recovered from (refunded to) customers through rates when the income taxes actually become payable (recoverable). The Company has recognized this deferred income tax liability with an offsetting increase in regulatory assets. Net regulatory asset for deferred income taxes at December 31, 2018 was $212,900,000.

**Cost Recovery Deferral**

In 2016 there was an over-recovery of revenue due to a July 1, 2016 rate implementation date. In Order No. P.U. 18 (2016), the Board approved amortization from July 1, 2016 to December 31, 2018 to provide recovery in customer rates of any 2016 revenue shortfall associated with the July 1, 2016 rate implementation. The over-recovery of revenue was approximately $2,580,000 with accumulated amortization of $2,580,000 over 2016 through 2018, resulting in a net regulating liability of $Nil as at December 31, 2018.

**Future Removal and Site Restoration Provision**

The Future Removal and Site Restoration Provision account represents amounts collected in customer electricity rates over the life of certain property, plant, and equipment which are attributable to removal and site restoration costs that are expected to be incurred in the future. The balance is calculated using current depreciation rates. For 2018 the balance in this account was $160,047,000 (2017 - $151,975,000).

**Based upon our analysis, nothing has come to our attention to indicate that changes in regulatory deferrals for 2018 are unreasonable.**

## Pension Expense Variance Deferral Account

***Scope:*** ***Review of calculation of the Pension Expense Variance Deferral Account ("PEVDA") and assess compliance with Order No. P.U. 43 (2009)***

In Order No. P.U. 43 (2009) the Board approved the creation of the Pension Expense Variance Deferral Account. PEVDA was created to capture the difference between the annual pension expense approved for the test year revenue requirement and the actual pension expense computed in accordance with accounting standards for any subsequent year. The purpose of the PEVDA is to adjust the variability related to factors outside of the Company's control, primarily due to changes in discount rates. The balance in the PEVDA is a charge or credit to the Rate Stabilization Account as of the 31st day of March in the year in which the difference arises.

The 2018 PEVDA was calculated at $273,942. This balance was transferred to the Rate Stabilization Account as a charge on March 31, 2018 in accordance with Order No. P.U. 43 (2009).

**We confirm that the 2018 PEVDA is calculated in accordance with Order No. P.U. 43 (2009).**

## Other Post-Employment Benefits Cost Variance Deferral Account

***Scope:*** ***Review the calculation of the Other Post-Employment Benefits Cost Variance Deferral Account ("OPEBVDA") and assess compliance with Order No. P.U. 31(2010)***

In Order No. P.U. 31 (2010) the Board approved the creation of the Other Post-Employment Benefits Cost Variance Deferral Account. OPEBVDA was created to capture the difference between the annual Other Post-Employment Benefits ("OPEBs") expense approved for the test year revenue requirement and the actual OPEBs expense computed in accordance with accounting standards for any subsequent year. The purpose of the OPEBVDA is to adjust the variability related to factors outside the Company's control, primarily due to changes in discount rates. The OPEBs expense for the year is the total of (i) the OPEBs expense for regulatory purposes for the year, and (ii) the amortization of OPEBs regulatory asset for the year. The balance in the OPEBVDA is a charge or credit to the Rate Stabilization Account as of the 31st day of March in the year in which the difference arises.

The 2018 OPEBVDA was calculated at ($2,053,764). This balance was transferred to the Rate Stabilization Account as a charge on March 31, 2018 in accordance with Order No. P.U. 31 (2010).

**We confirm that the 2018 OPEBVDA is calculated in accordance with Order No. P.U. 31 (2010).**

## Productivity and Operating Improvements

***Scope:*** ***Review the Company's initiatives and efforts with respect to productivity improvements, rationalization of operations and expenditure reductions. Inquire as to the Company's reporting on Key Performance Indicators.***

On an ongoing basis, Newfoundland Power undertakes initiatives aimed at improving reliability of service and efficiency of operations. According to the information provided by Newfoundland Power, the productivity and operational improvements undertaken in 2018 are as follows:

1. Made capital investments of $92 million of which over 57% were targeted directly to replacing or refurbishing deteriorated and defective equipment.

2. Continued Feeder Upgrades under the "Rebuild Distribution Lines Program".

3. Continued work under the Transmission Line Strategy.

4. Continued the Substation Modernization and Refurbishment program.

5. Continued to install down line reclosers to provide for improved control over the distribution system along with the ability to locate and isolate system trouble.

6. Developed regional and departmental safety action plans to help drive accountability and improve safety culture. A safety consultant from The Engine Room was contracted to provide safety leadership training and carry out work observation coaching with Operations Supervisors across the island.

7. The Company formed an internal "Green Team" to improve its emphasis on environmental initiatives. The focus was to educate employees about established sustainability programs and to help guide operations improvements in the direction of sustainability.

8. Launched a new incident management system. The new Itelex module will functionally replace the previous system and offer new and improved ways to manage and report on safety and environmental metrics. A comprehensive training program was delivered to its internal user group of approximately 160 employees.

9. Development, integrations and testing continued on new outage management system.

10. WorkplaceNL conducted a PRIME audit for 2015, 2016, and 2017, to ensure Newfoundland Power's compliance with provincial workplace health, Safety, and compensation commission protocols. The Company was found to be in compliance for all three years. This means the Company continues to be eligible for incentives that reduce premiums paid to WorkplaceNL.

11. There were a number of technology related enhancements made in the second quarter to improve the Geographic Information System ("GIS") functionality. They Include:

    a. Improved GIS access and maintenance job planning by providing field crews view of the electrical system components while on a job site.
    b. Enhanced mobile mapping technology allowing field staff to provide real time "mark ups" to the GIS system which will improve GIS data accuracy.
    c. Mapping of deficiencies found during distribution system inspections will allow for improved efficiency in maintenance work planning and execution.

12. The Company launched a new version of newfoundlandpower.com with easier navigation and accessibility of customer self-service functions. The website has a more modern, clean and friendly appearance, which adapts to viewing on any screen size or device.

13. Enhanced the technology used to record and manage the Company's interactions with customers and the consolidation of customer notes and Company action items will streamline and improve the customer interaction experience.

14. The Company has implemented a Cybersecurity Risk Management Program which includes the development of a 2-year cybersecurity plan to prioritize the Company's cybersecurity investments and resources in order to improve cybersecurity controls and mitigate risk. This includes improvements to

cybersecurity controls documentation and the implementation of new technology to improve access to digital assets in substations.

15. An email promotion conducted in the 4th quarter resulted in approximately 1,000 new accounts being enrolled in the e-bills program in 2018. Approximately 47% of all billed customers now receive their bills electronically.

16. The Company purchased the first electric vehicle in its fleet.

***Performance Measures***

Newfoundland Power notes its performance targets focus on the Company's ability to reasonably control costs, while continuing to improve service reliability, maintain good customer service satisfaction results and a strong safety and environmental record.

The performance targets are established based on historical data, adjusted for anomalies where necessary, and reflect either stable performance or continued improvement over time. Actual results are tracked using various internal systems and processes. They are reported and re-forecasted internally on a monthly basis.

The following table lists the principal performance measures used in the management as provided by the Company.

| Category | Measure | Actual 2016 | Actual 2017 | Actual 2018 | Plan 2018 | Measure Achieved |
|---|---|---|---|---|---|---|
| Reliability | Outage Hours/Customer (SAIDI) – excluding Hydro loss of supply[1] | 2.24 | 2.28 | 2.65 | 2.27 | No |
| | Outage/Customer (SAIFI) – excluding Hydro loss of supply[1] | 1.36 | 1.66 | 1.67 | 1.86 | Yes |
| | Plant Availability (%)[2] | 85.3 | 91.3 | 96.3 | 95.0 | Yes |
| Customer Satisfaction | % of Satisfied Customers as measured by Customer Satisfaction Survey | 86.0 | 86.5 | 85.6 | 86.5 | No |
| | Call Centre Service Level (% per second) | 81/60[4] | 80/60 | 81/60 | 80/60 | Yes |
| | Trouble Call Responded to Within 2 Hours (%) | 87.0 | 87.0 | 85.0 | 85.0 | Yes |
| Safety | All Injury/Illness Frequency Rate | 1.3 | 0.7 | 0.9 | 0.7 | No |
| Financial | Earnings (millions) | $40.0 | $41.0 | $41.2 | $40.0 | Yes |
| | Gross Operating Cost/Customer[3] | $260 | $264 | $225 | $223 | No |

[1] 2016 reliability statistics exclude the impact of a wind storm in November. 2017 reliability statistics exclude the impact of a snow storm in December and a snow storm in March. 2018 reliability statistics exclude the impact of wind storms in April and November and a power transformer failure in November.

[2] Includes total hours of plant availability. Q4 Regulatory Report excludes the hours the generation unit is out of service due to system disruptions and major plant refurbishment.

[3] Excludes Pension, OPEBs and early retirement costs.

The following table compares whether the Company measures were achieved during the 2016, 2017, and 2018 years:

| Category | Measure | Measure Achieved 2016 | Measure Achieved 2017 | Measure Achieved 2018 |
|---|---|---|---|---|
| Reliability | Outage Hours/Customer (SAIDI) – excluding Hydro loss of supply | Yes | Yes | No |
| | Outage/Customer (SAIFI) – excluding Hydro loss of supply | Yes | Yes | Yes |
| | Plant Availability (%) | No | No | Yes |
| Customer Satisfaction | % of Satisfied Customers as measured by Customer Satisfaction Survey | No | No | No |
| | Call Centre Service Level (% per second) | Yes | Yes | Yes |
| | Trouble Call Responded to Within 2 Hours (%) | Yes | Yes | Yes |
| Safety | All Injury/Illness Frequency Rate | No | Yes | No |
| Financial | Earnings (millions) | Yes | Yes | Yes |
| | Gross Operating Cost/Customer | Yes | Yes | No |