Section 3: Finance/Fair Return

Q. Reference: "2025/2026 General Rate Application," Newfoundland Power Inc., December 12, 2023, vol. 1, Evidence, sec. 3.3.2, p. 3-31, f.n. 64.
Please provide the annual Grant Thornton reports on Newfoundland Power's Annual Return filings for the past five years.

A. Attachments A through E provide Grant Thornton's *Annual Financial Review of Newfoundland Power Inc.* for 2017 through 2021. The annual financial review for 2022 is currently ongoing.

Attachments A through E are available in electronic format on Newfoundland Power's stranded website at: https://ftp.nfpower.nf.ca/.

Grant Thornton
2017 Annual Financial Review of Newfoundland Power Inc.

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Board of Commissioners of Public Utilities
2017 Annual Financial Review of Newfoundland Power Inc.

Contents

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 2017 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 2017 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 2017 was $1,092,254,000 compared to average rate base for 2016 of $1,061,044,000. The Company's calculation of the return on average rate base for 2017 was 7.22% (2016 – 7.31%) compared to an approved rate of return of 7.19%. The actual rate of return was within the range approved by the Board (7.01% to 7.37%). 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 2017 was $486,557,000 (2016 - $475,765,000). The Company's actual return on average common equity for the year ended December 31, 2017 was 8.93% (2016 – 8.90%). 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 2017 was 8.93% 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 12.14% under budget in 2017. The capital expenditures were under the approved budget (including projects carried over from prior years) on a net basis by $9,886,000 (6.79%). However, for each category of expenditure, the variances ranged from an over-budget of 6.54% to an under-budget of 32.74%. Significant variances are explained in our report.

The Company experienced a 0.08% increase in revenue from rates in 2017 as compared to 2016. The increase can be explained by the full year impact of an increase in customer energy rates effective July 1, 2016 related to the Company's 2016/2017 General Rate Application ("GRA"), partially offset by a decrease in GWh sold.

Overall, net operating expenses increased by $1,782,000 from 2016 to 2017. 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 2017 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 2016 Pension Expense Variance Deferral Account (PEVDA) operated in accordance with Order No. P.U. 43 (2009).

Based on our review, the 2016 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 2017 the Company met seven out of nine of its planned performance measures. The Company fell short of its targets in the following categories: "Plant Availability" and "% of Satisfied Customers as measured by Customer Satisfaction Survey".

Introduction

This report to the Board of Commissioners of Public Utilities ("the Board") presents our observations, findings and recommendations with respect to our 2017 Annual Financial Review of Newfoundland Power Inc. ("the Company") ("Newfoundland Power").

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 2017 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, 2017 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, 2018. 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, 2018, the Company filed a revised system of accounts as part of its 2017 Annual Report. According to Newfoundland Power, the revisions principally relate to minor wording changes to improve clarity and accuracy of account descriptions and two accounts that were inadvertently deleted last year were reinstated. These changes are not significant and the Company believes it will enhance its ability to provide sufficient information to meet the reporting requirements of the Board.

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, 2017 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 2017 was $1,092,254,000 which is an increase of $31,210,000 (2.94%) over the average rate base for 2016 of $1,061,044,000. 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 2017; 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, 2017 Test Year and 2016 (all figures shown are averages):

(000)'s	2017	2017 Test Year	2016
Net Plant Investment (average)			
Plant Investment	$1,772,877	-	$1,703,478
Accumulated Depreciation	(709,985)	-	(681,742)
CIAC's	(37,234)	-	(35,166)
	1,025,658	1,041,415	986,570
Additions to Rate Base (average)			
Deferred Charges (a)	93,498	94,045	96,877
Cost Recovery Deferral for Seasonal/TOD Rates (b)	-	-	25
Cost Recovery Deferral for Hearing Costs (c)	512	600	341
Cost Recovery Deferral – Conservation (d)	12,710	11,991	9,384
Customer Finance Programs (e)	1,419	1,136	1,276
Demand Management Incentive Account (f)	745	-	-
Weather Normalization Reserve (g)	3,246	-	3,066
	112,130	107,772	110,969
Deductions from Rate Base (average)			
Other Post-Employment Benefits (h)	49,334	48,719	42,646
Customer Security Deposits (i)	926	700	1,036
Accrued Pension Obligation (j)	5,429	5,428	5,120
Deferred Income Taxes (k)	3,051	3,728	1,727
Excess Earnings (l)	-	-	25
Cost Recovery Deferral – 2016 Cost Recovery Deferral (m)	1,084	1,099	723
	59,824	59,674	51,277
Average Rate Base before Allowances	1,077,964	1,089,513	1,046,262
Rate Base Allowances			
Materials and Supplies	6,137	6,788	6,464
Cash Working Capital	8,153	8,401	8,318
	14,290	15,189	14,782
Average Rate Base	$ 1,092,254	$ 1,104,702	$ 1,061,044

(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 \$93,498,000 (2016 - \$96,877,000) included in the 2017 rate base consists of average deferred pension costs of \$93,396,000 (2016 - \$96,802,000) and credit facility costs of \$102,000 (2016 - \$75,000). The Company has included a schedule of these costs in Return 8.

(b) In Order No. P.U. 8 (2011) the Board approved the Optional Seasonal Rate Revenue and Cost Recovery Account. Pursuant to Order No. P.U. 8 (2011), "on December 31st of each year from 2011 until further order of the Board, this account shall be charged with: (i) the current year revenue impact of making the Domestic Seasonal – Optional Rate available to customers and (ii) the operating costs associated with implementing the Domestic Seasonal – Optional and the Time-of-Day Rate Study". In the 2016/2017 GRA, the company did not propose that the Optional Seasonal Rate Revenue and Cost Recovery Account be maintained beyond 2015.

(c) 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, relating to these costs. The 2017 average rate base includes an addition of \$512,000 (2016 - \$341,000) which represents the unamortized average balance of the original \$853,000.

(d) 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. Included in the calculation of the average rate base for 2017 is \$12,710,000 (2016 - \$9,384,000) related to this deferral.

(e) Customer Finance Programs are comprised of loans provided to customers related to customer conservation programs and contributions in aid of construction. The 2017 average rate base incorporates \$1,419,000 (2016 - \$1,276,000) related to these programs.

(f) The 2016 balance of the Demand Incentive Account was \$Nil as there was no supply cost variance outside the Deadband. 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. The 2017 average rate base incorporates \$745,000 (2016 - \$Nil) related to this account.

(g) During 2017, 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 \$1,721,000 in 2017 (2016 – \$4,411,000 increase).

Other transfers:

i. $112,000 transfer increase (2016 – $102,000 increase) to the reserve related to the after tax impact of the Degree Day Normalization Reserve Transfer.
ii. $4,883,000 transfer decrease (2016 - $1,823,000 decrease) to the reserve related to the after tax impact of the Hydro Production Equalization Reserve transfer.

The net impact was a net increase to the reserve of $3,050,000 (2016 - $2,690,000 decrease). The ending balance in this reserve account totaled ($4,771,000) compared to a balance of ($1,721,000) at December 31, 2016 (an average of ($3,246,000) for 2017 (2016 – ($3,066,000)).

(h) Other Post-Employment Benefits is equal to the difference, at December 31, 2017, between the OPEBs liability of $80,616,000 and the OPEBs asset of $28,032,000. The calculation of the 2017 average rate base of $49,334,000 is equal to the average of the December 31, 2017 net liability of $52,584,000 and the December 31, 2016 net liability of $46,083,000.

(i) 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 2017 average rate base incorporates $926,000 (2016 - $1,036,000) related to customer security deposits.

(j) The 2017 average rate base calculation incorporates $5,429,000 (2016 - $5,120,000) 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.

(k) 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 2017 average rate base is ($2,297,000) and ($13,176,000) respectively. The remaining balance of the deferred income tax liability in the amount of $18,523,000 relates to capital assets. This results in an average balance for deferred income tax liability of $3,051,000 (2016 - $1,727,000).

(l) In Order No. P.U. 23 (2013) the Board approved the definition of the Excess Earnings Account. In 2013, Newfoundland Power's regulated earnings exceeded the upper limit of allowed regulated earnings by $49,000 after tax. The average rate base originally filed in the 2013 Return 3 and Return 13 used an understated average rate base balance of $915,612,000. The understated average rate base produced an excess earnings liability of $68,000 ($49,000 after tax). An average rate base of $915,820,000 was subsequently filed by the Company in Schedule D of its 2015 Capital Budget Application. This revised rate base produces excess earnings of $46,000 ($33,000 after tax). The Company has noted as the original calculation is not materially higher than the revised calculation, it has not adjusted the excess earnings account. This represents a benefit to the customer. The 2017 average rate base incorporates $Nil (2016 - $25,000) related to this account.

(m) 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) was recorded in 2017, relating to this over-recovery of revenue. The 2017 average rate base includes deduction of $1,084,000 (2016 - $723,000) which represents the unamortized average balance of the original $1,806,000.

The net change in the Company's average rate base from 2016 to 2017 can be summarized as follows:

(000's)	2017	2016
Average rate base - opening balance	$ 1,061,044	$ 1,019,082
Change in average deferred charges and deferred regulatory costs	(268)	(3,375)
Average change in:		
Plant in service	69,398	74,289
Accumulated depreciation	(28,243)	(24,509)
Contributions in aid of construction	(2,068)	(1,197)
Weather normalization reserve	181	1,681
Other post employment benefits	(6,688)	(6,824)
Future income taxes	(1,324)	172
Rate base allowances	(492)	1,763
Demand Management Incentive Acct	745	-
Other rate base components (net)	(31)	(38)
Average rate base - ending balance	$ 1,092,254	$ 1,061,044

Based upon the results of the above procedures we did not note any discrepancies in the calculation of the 2017 average rate base, and therefore conclude that the 2017 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 2017 was 7.22% (2016 – 7.31%). 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 2017, 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 2015 to 2017 is set out in the table below.

	2017	2016	2015
Actual Return on Average Rate Base	7.22%	7.31%	7.48%
Upper End of Range set by the Board	7.37%	7.39%	7.68%
Lower End of the Range set by the Board	7.01%	7.03%	7.32%

The Board approved the Company's rate of return on average rate base of 7.19% in a range of 7.01% to 7.37% for 2016 in Order No. P.U. 25 (2016). As noted above, the Company's actual return on average rate base for 2017 was 7.22% which was inside the range set by the Board.

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

The actual rate of return for 2015 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 2017 as reported in Return 24 is as follows:

	2017 Average		2016	2015
	(000's)	**Percent**	Percent	Percent
Debt	**$586,726**	**54.22%**	54.17%	54.85%
Preferred equity	**8,924**	**0.82%**	0.84%	0.88%
Common equity	**486,557**	**44.96%**	44.99%	44.27%
	$1,082,207	**100.00%**	100.00%	100.00%

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 2017 was 6.12% which represents a 15 bps decrease from 2016 embedded cost of debt of 6.27%.

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, 2017 is included on Return 27 of the annual report to the Board. The average common equity for 2017 was $486,557,000 (2016 - $475,765,000). The Company's actual return on average common equity for 2017 was 8.93% (2016 – 8.90%).

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 2017 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 2017 was 8.93% 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)	2017	2016	2015
Net income	**$41,526**	$ 40,508	$ 39,314
Income taxes	**12,882**	11,851	10,925
Interest on long term debt	**35,013**	34,846	35,020
Interest during construction	**(1,025)**	(1,304)	(1,240)
Other interest and amortization of debt discount costs	**893**	1,090	1,361
Total	**$89,289**	$ 86,991	$ 85,380
Interest on long term debt	**$35,013**	$34,846	$35,020
Other interest and amortization of debt discount costs	**893**	1,090	1,361
Total	**$35,906**	$35,936	$36,381
Interest Coverage (times)	**2.5**	2.4	2.3

The above table shows that the interest coverage increased by 0.1 times from 2016 to 2017.

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 2017 is 2.5 times.

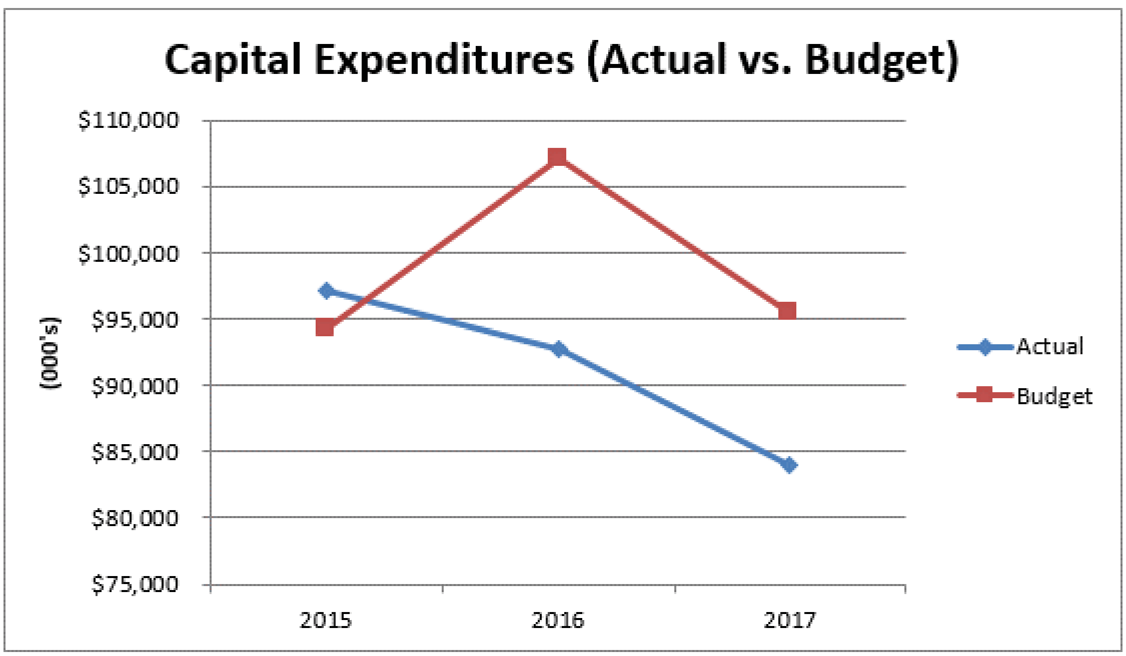
Capital Expenditures

Scope: ***Review the Company's 2017 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 2015 to 2017:

($000's)	2015	2016	2017	Notes
Actual	$ 97,155	$ 92,727	$ 83,921	1
Budget	$ 94,211	$ 107,028	$ 95,521	
Over (under) budget	3.12%	(13.36%)	(12.14%)	

Note 1: Total expenditures per the 2017 Capital Budget report includes the carryover amount of $5,770,000 for a total of $89,691,000. The carryover amount is made up of five projects included in the following categories: $1,476,000 to generation - hydro; $750,000 to substations; $475,000 to transmission; $2,846,000 to distribution and $223,000 to Transportation. According to the Company, these expenditures will occur in 2018.



The following table provides a summary of the capital expenditure activity in 2017 as reported in the Company's *"2017 Capital Expenditure Report"*:

($000's)	Capital Budget			Actual Expenditures		
	Prior Years	2017	Total	Prior Years	2017	Total
2017 Capital Projects (1)	$ -	$ 95,521	$ 95,521	$ -	$ 83,921	$ 83,921
2016 Projects Carried to 2017 & Multi Year Projects						
Facility Rehabilitation - 2016 (2)	1,462	-	1,462	1,252	619	1,871
Public Safety Around Dams - 2016	883	-	883	559	413	972
Substation Refurbishment and Modernization - 2016 (3)	7,871	-	7,871	5,980	914	6,894
Transmission Line Rebuild - 2016 (4)	6,067	-	6,067	4,046	140	4,186
Distribution Reliability Initiative - 2016	1,463	-	1,463	359	1,093	1,452
Distribution Feeder Automation - 2016 (5)	565	-	565	265	99	364
Trunk Feeders - 2016 (6)	1,607	-	1,607	1,134	14	1,148
St. John's Main Underground Refurbishment - 2016	1,950	-	1,950	326	1,624	1,950
Purchase Vehicles and Aerial Devices - 2016	3,258	-	3,258	2,353	1,024	3,377
Fibre Optic Network - 2016 (7)	409	-	409	109	120	229
Application Enhancements - 2016	1,143	-	1,143	989	154	1,143
System Upgrades - 2016	1,718	-	1,718	1,244	390	1,634
Pierre's Brook Plant Refurbishment - Multi Year	15,762	-	15,762	14,793	239	15,032
SCADA System Replacement - Multi Year	5,675	-	5,675	5,335	276	5,611
OMS System Replacement - Multi Year (8)	149	-	149	63	-	63
	49,982	-	49,982	38,807	7,119	45,926
Grand Total	**$ 49,982**	**$ 95,521**	**$ 145,503**	**$ 38,807**	**$ 91,040**	**$ 129,847**

(1) Approved by Order No. P.U. 39 (2016), Order No. P.U. 6 (2017), and Order No. P.U. 19 (2017).
(2) The Company has noted that the unfavorable budget variance was primarily related to the higher than average expenditure on equipment replacements due to in-service failures, as it was $198,000 higher than the historical average.
(3) The Company has noted that the favorable variance was related to the fact that cost estimates assumed that most of the work would be done by contractors. However, due to lower than anticipated substation maintenance requirements during the year, Company personnel were able to complete much of the construction and commissioning work.
(4) The Company has noted that the favorable budget variance primarily resulted from the corduroy road project being completed during the 2015 portion and therefore no additional expenditures were required in 2016. The variance was also contributed to by lower than expected contractor pricing and identified deficiencies in 2016 costing $300,000 less than the historical averages.
(5) The Company has noted that the budget variance is a result of installations that were delated until 2017 because several pieces of equipment failed factory acceptance testing.
(6) The Company has noted that the favorable budget variance was principally due to the elimination of a requirement to upgrade the vault at the old Battery Hotel when the property was purchased by MUN.
(7) The Company has noted that the favorable budget variance is related to reduced materials and labor requirements for the project as the final route identified during detailed engineering was shorter than the route used to prepare the budget estimate.
(8) The Company has noted that the variance is related to the initial stage of the 2016/2017 project involving a market assessment of outage management systems and the development of a detailed system specification. However, following the initial assessment it was decided that a different scope was necessary and as a result, the Company submitted a revised project as part of its 2018 Capital Budget Application.

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

($000's)	2017 Budget (1)	2017 Actuals (2)	Variance	Carryover	Variance Including Carryover	%
Generation - Hydro	$ 25,133	$ 22,559	$ (2,574)	$ 1,476	$ (1,098)	(4.37%)
Generation - Thermal	234	242	8	-	8	3.42%
Substation	26,110	22,371	(3,739)	750	(2,989)	(11.45%)
Transmission	12,778	10,410	(2,368)	475	(1,893)	(14.81%)
Distribution	53,802	48,367	(5,435)	2,846	(2,589)	(4.81%)
General property	1,502	1,456	(46)		(46)	(3.06%)
Transportation	6,714	6,930	216	223	439	6.54%
Telecommunications	507	341	(166)	-	(166)	(32.74%)
Information systems	13,973	13,204	(769)	-	(769)	(5.50%)
Unforeseen	750	-	(750)	-	(750)	(100.00%)
General expenses capitalized	4,000	3,967	(33)	-	(33)	(0.83%)
Total	**$ 145,503**	**$ 129,847**	**$ (15,656)**	**$ 5,770**	**$ (9,886)**	**(6.79%)**

1 - Includes prior years projects and current year budgeted amounts as there were projects incomplete at the previous year ends.
2 - 2017 actuals include the total expense for projects carried forward from the years 2015 to 2016.

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 $15,656,000 and by $9,886,000 (6.79%) when carryover amounts are taken into account. However, for each category of expenditure, the variances ranged from an over-budget of 6.54% for the Transportation category to an under-budget of 32.74% for the Telecommunications 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	314
Rose Blanche Plant Refurbishment	280
Tors Cove Plant Refurbishment	882
Substation Refurbishment and Modernization	750
Transmission Line Rebuild	475
Meters	300
Distribution Reliability Initiative	700
Distribution Feeder Automation	420
St. John's Main Underground Refurbishment	1,426
Purchase Vehicles and Aerial Devices	223
Total Carryover	**$ 5,770**

The Company has provided detailed explanations on budget to actual variances in its “2017 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 2017 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 it 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 -13.36% in 2016 and -12.14% in 2017. According to Newfoundland Power, this is related to the fact that for both years, there were significant carryovers for work not completed on schedule. In 2016, there were forecast carryovers totaling $7,284,000 which reduced the variance to 6.56%. Actual 2016 capital expenditures in 2017 associated with these carryovers were $7,319,000 resulting in a 6.52% variance for 2016 capital projects. Likewise, in 2017, there were forecast carryovers totaling $5,770,000 as seen above. This reduced the variance from 12.19% to 6.1%.

Based on our review, the Company had no reporting obligations under the Capital Budget Application Guidelines Policy #1900.6 Section B with respect to the allowance for unforeseen items as the allowance was not used during the year.

Capital Expenditure Reports

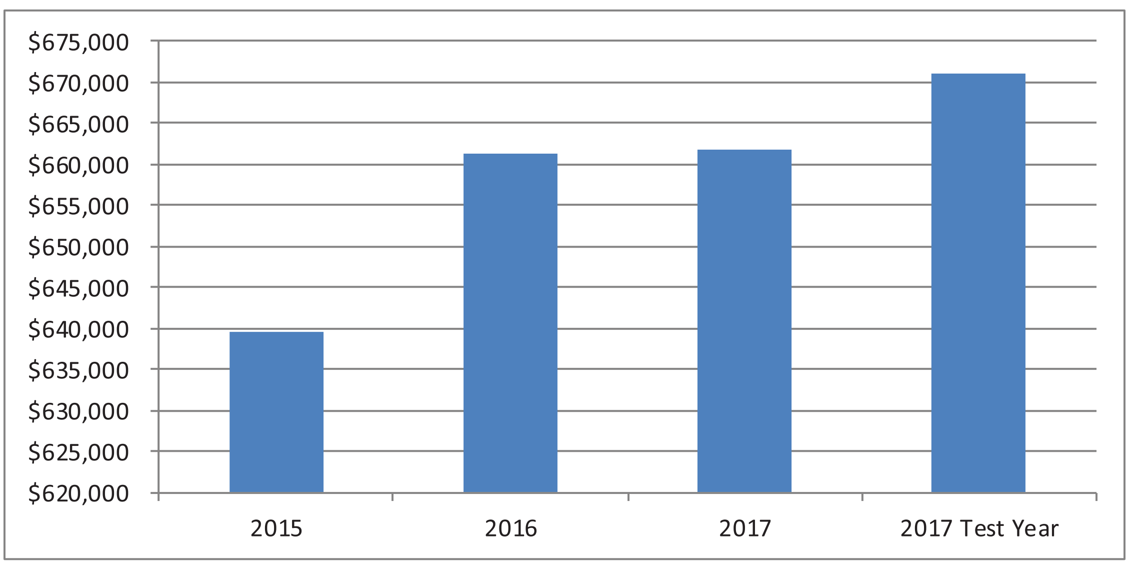
Confirmation was received from the Board that the Company filed quarterly Capital Expenditure reports for the 2017 calendar year.

Revenue

Scope: Review the Company's 2017 revenue in comparison to prior years and follow up on any significant variances.

We have compared the actual revenues for 2015 to 2017 to assess any significant trends. The results of this analysis of revenue by rate class are as follows:

($000's)	2015	2016	2017	2017 Test Year
Residential	$ 403,910	$ 420,159	$ 422,237	$ 428,105
General Service				
0-100 kW	85,093	88,362	88,507	90,164
110-1000 kVA	93,725	96,404	95,565	97,515
Over 1000 kVA	38,400	38,021	37,099	36,214
Streetlighting	15,541	15,928	16,149	16,110
Discounts forfeited	2,962	2,507	2,327	2,897
Revenue from rates	$ 639,631	$ 661,381	$ 661,884	$ 671,005
Year over year percentage change	3.25%	3.29%	0.08%	1.36%



The above graph demonstrates that the Company has seen a 0.08% increase in revenue from rates in 2017 as compared to 2016. The increase is primarily due to the full year impact of an increase in customer energy rates effective July 1, 2016 related to the Company's 2016/2017 GRA, partially offset by a decrease in GWh sold. There was a 0.47% decrease in the overall demand in GWh for 2017. For residential sales there was an increase of 0.49% in 2017 revenue from 2016.

The comparison by rate class of 2017 actual revenues to 2017 budget is as follows:

($000's)	2016	2017	2017 Plan	Actual - Plan Variance	%
Residential	$ 420,159	$ 422,237	$ 426,897	$ (4,660)	(1.09%)
General Service					
0-100 kW	88,362	88,507	90,314	(1,807)	(2.00%)
110-1000 kVA	96,404	95,565	97,534	(1,969)	(2.02%)
Over 1000 kVA	38,021	37,099	36,228	871	2.40%
Streetlighting	15,928	16,149	16,116	33	0.20%
Discounts forfeited	2,507	2,327	2,895	(568)	(19.62%)
Total revenue from rates	$ 661,381	$ 661,884	$ 669,984	$ (8,100)	(1.21%)

We have also compared the 2017 budget energy sales in GWh to the actual sold in 2017:

	2016	2017	2017 Plan	Actual - Plan Variance	%
Residential	3,655.6	3,644.8	3,675.9	(31.1)	(0.85%)
General Service					
0-100 kW	797.7	793.6	811.2	(17.6)	(2.17%)
110-1000 kVA	1,010.4	1,010.2	1,027.9	(17.7)	(1.72%)
Over 1000 kVA	453.8	440.8	433.1	7.7	1.78%
Streetlighting	32.6	32.8	32.8	-	0.00%
Total	5,950.1	5,922.2	5,980.9	(58.7)	(0.98%)

Actual 2017 revenue from rates was lower than 2017 Plan with an overall decrease in actual sales of $8,100,000 (1.21%) from the 2017 Plan. There was a 0.98% decrease in GWh sold in 2017 compared to 2017 Plan. The largest variance in revenue can be seen in the Residential and 110-1000 KVA class where revenues decreased by $4,660,000 (1.09%) and $1,969,000 (2.02%) 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.

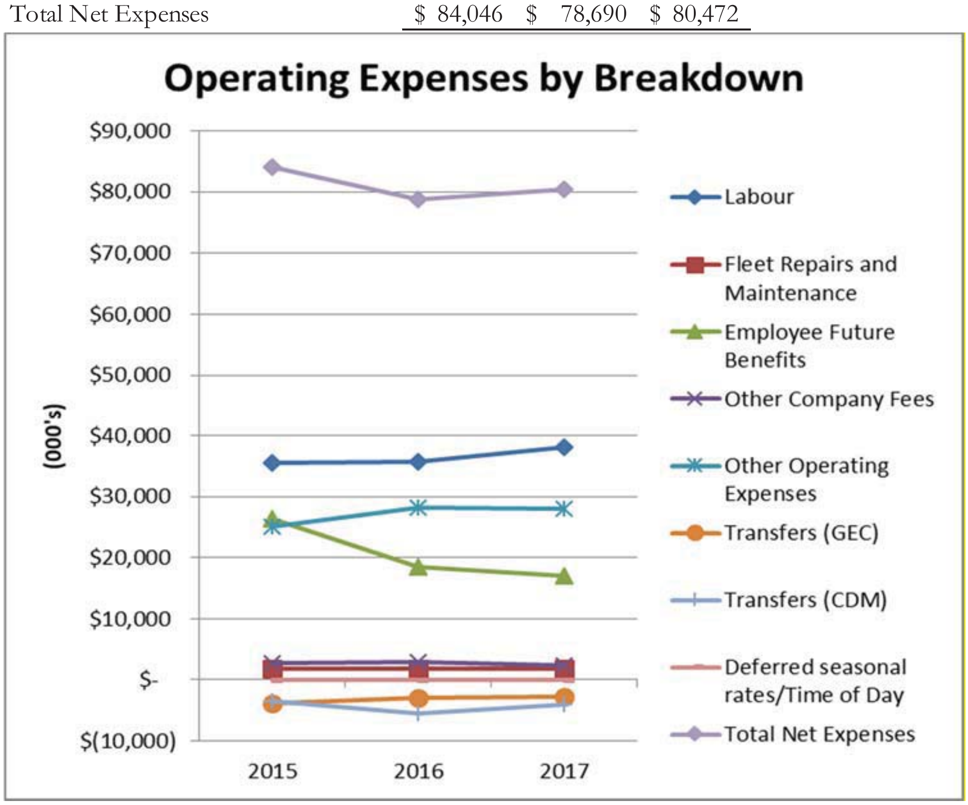
(000's)	Actual 2017	Test Year 2017	Actual 2016	Actual 2015	Variance Actual-Test	Variance 2017-2016
Labour	$ 39,341		$ 36,770	$ 36,485	$ -	$ 2,571
Reclass OPEB labour cost	(1,173)		(981)	(969)	-	(192)
Total Labour	38,168	37,956	35,789	35,516	212	2,379
Vehicle expense	1,854	1,586	1,797	1,786	268	57
Operating materials	1,528	1,674	1,425	1,583	(146)	103
Inter-company charges	2,002	2,295	2,145	1,560	(293)	(143)
Plants, Subs, System Oper & Bldgs	2,796	2,314	2,770	2,367	482	26
Travel	1,235	1,274	1,160	1,052	(39)	75
Tools and clothing allowance	1,234	1,155	1,161	1,130	79	73
Miscellaneous	1,879	1,994	1,821	1,765	(115)	58
Conservation	2,981	2,895	4,253	2,466	86	(1,272)
Taxes and assessments	1,252	1,173	1,214	1,123	79	38
Uncollectible bills	1,386	1,337	1,194	1,313	49	192
Insurance	1,326	1,266	1,293	1,260	60	33
Severance & other employee costs	102	74	47	72	28	55
Education, training, employee fees	339	363	275	298	(24)	64
Trustee and directors' fees	489	476	471	462	13	18
Other company fees	2,296	3,265	2,944	2,757	(969)	(648)
Stationary & copying	214	285	266	230	(71)	(52)
Equipment rental/maintenance	806	819	838	746	(13)	(32)
Communications	2,927	3,201	2,959	3,184	(274)	(32)
Advertising	1,592	1,717	1,519	1,251	(125)	73
Vegetation management	2,099	1,863	1,820	1,766	236	279
Computing equipment & software	1,451	1,455	1,359	1,058	(4)	92
Total Other	31,788	32,481	32,731	29,229	(693)	(943)
Pension & early retirement program	8,675	7,622	9,763	17,702	1,053	(1,088)
OPEB's	8,364	8,228	8,678	8,653	136	(314)
Total employee future benefits	17,039	15,850	18,441	26,355	1,189	(1,402)
Total gross expenses	86,995	86,287	86,961	91,100	708	34
Transfers (GEC)	(2,847)	(2,944)	(2,955)	(3,809)	97	108
CDM amortization	2,741	2,533	1,712	1,053	208	1,029
Deferred CDM program costs	(6,758)	(7,231)	(7,200)	(4,611)	473	442
Deferred seasonal rates/TOD	-	-	-	(9)	-	-
Deferred regulatory costs	341	400	172	322	(59)	169
Total net expenses	$ 80,472	$ 79,045	$ 78,690	$ 84,046	$ 1,427	$ 1,782

The above table provides details of operating and general expenses (including non-regulated expenses) by "breakdown" for 2015, 2016, 2017 Test Year and 2017 Actual.

Overall, net operating expenses increased by $1,782,000 from 2016 to 2017. 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 2017 are unreasonable. Actual net operating expenses were also higher than the test year amount by $1,427,000. The increase in actual compared to test year is primarily a result of the pension and early retirement program expense as, according to the Company, there was a lower expected return on plan assets for 2017. This increase was somewhat offset by lower than expected costs related to defined contribution plans.

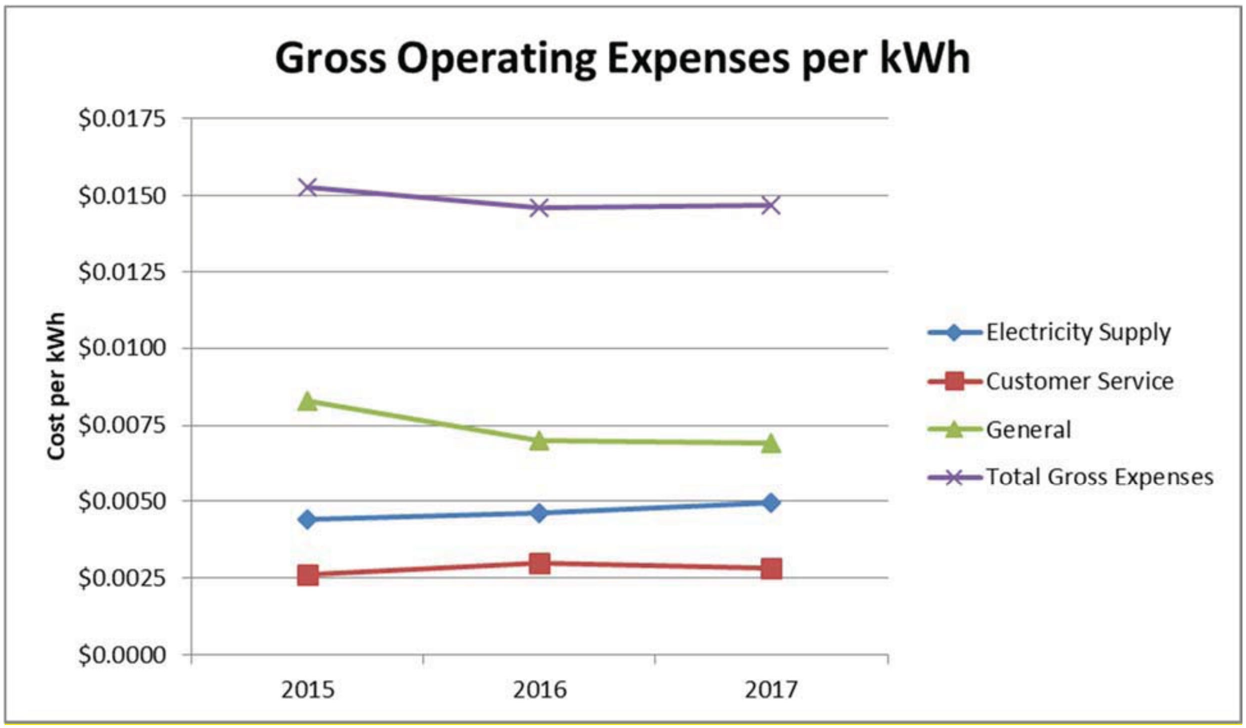
Our detailed review of operating expenses was conducted using the breakdown as documented in the above table. It should also be noted that our review is based upon gross expenses before allocation to GEC and CDM. The following table and graph shows the trend in operating expenses by breakdown for the period 2015 to 2017.

	Actual		
(000's)	**2015**	**2016**	**2017**
Labour	$ 35,516	$ 35,789	$ 38,168
Fleet Repairs and Maintenance	1,786	1,797	1,854
Employee Future Benefits	26,355	18,441	17,039
Other Company Fees	2,757	2,944	2,296
Other Operating Expenses	25,008	28,162	27,979
Transfers (GEC)	(3,809)	(2,955)	(2,847)
Transfers (CDM)	(3,558)	(5,488)	(4,017)
Deferred seasonal rates/Time of Day	(9)	-	-
Total Net Expenses	$ 84,046	$ 78,690	$ 80,472



The relationship of operating expenses to the sale of energy (expressed in kWh) from 2015 to 2017 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
2015	5,956,600	$ 26,191	$ 0.0044	$ 15,474	$ 0.0026	$ 49,435	$ 0.0083	$ 91,100	$ 0.0153
2016	5,950,100	$ 27,400	$ 0.0046	$ 17,663	$ 0.0030	$ 41,613	$ 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



The table and graph show that total gross expenses per kWh have increased by approximately 0.68% compared to 2016.

There was a decrease in General Costs of $0.7 million and Customer Service Costs of $0.9 million which were offset by an increase in Electricity Supply Costs of $2.0 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 2015 to 2017 (including 2017 plan) is as follows:

	Actual 2017	Plan 2017	Actual 2016	Actual 2015	Actual - Plan	Actual 2017-2016
Executive Group	**6.3**	**6.0**	6.0	6.0	0.3	0.3
Corporate Office	**20.0**	**21.8**	20.7	20.7	(1.8)	(0.7)
Finance	**88.9**	**91.5**	89.5	93.5	(2.6)	(0.6)
Egineering and Operations	**365.4**	**384.4**	406.9	418.5	(19.0)	(41.5)
Customer Relations	**84.3**	**90.0**	62.8	68.0	(5.7)	21.5
	564.9	**593.7**	585.9	606.7	(28.8)	(21.0)
Temporary employees	**46.3**	**37.8**	48.6	46.3	8.5	(2.3)
Total	**611.2**	**631.5**	634.5	653	(20.3)	(23.3)

The overall number of FTE's in 2017 compared to 2016 decreased by 23.3. The budgeted number of FTE's in the 2017 Plan was 631.5 versus actual of 611.2. The variances between 2017, 2017 Plan and 2016 are the result of the following:

- The Corporate Office is lower than plan due to timing of replacement hires for employee leaves.
- Finance is consistent with 2016 but lower than plan due to a shift of personnel to Engineering & Operations and Customer Relations as well as timing of replacement of personnel. The decrease is partially offset by the addition of a new Corporate Counsel position and a shift from contracted services for Technology.
- Engineering and operations is lower than plan and 2016 primarily due to the timing of replacement of personnel for retirements and leaves, as well as a reduction in Powerline Technicians and Engineering Technologists due to less load growth.
- Customer Relations is higher than 2016 due to a corporate reorganization to centralize customer service and meter positions under Customer Relations. 2017 is lower than plan due primarily to a shift in Customer Service Representatives from regular to temporary employees
- Temporary Employees is higher than plan because of a shift in Customer Service Representatives from regular to temporary employees. 2017 is lower than 2016 as the increase in Customer Service Representatives is more than offset by lower Meter Readers.

An analysis of salaries and wages by type of labour and by function from 2015 to 2017 is as follows:

(000's)	**Actual 2017**	Actual 2016	Actual 2015	**Variance 2017-2016**
Type				
Internal labour	**$ 64,399**	$ 63,608	$ 63,330	$ 791
Overtime	**6,807**	4,925	5,117	1,882
	71,206	68,533	68,447	2,673
Contractors	**12,883**	10,593	15,232	2,290
	$ 84,089	$ 79,126	$ 83,679	4,963
Function				
Operating	**$ 39,341**	$ 36,770	$ 36,485	2,571
Capital and miscellaneous	**44,748**	42,356	47,194	2,392
Total	**$ 84,089**	$ 79,126	$ 83,679	4,963
Year over year percentage change	6.27%	-5.44%	-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 2017 were $4,963,000 (6.27%) higher than 2016.

Internal labour costs in 2017 were higher than 2016 due to normal labour inflation, restoration efforts following storms and higher corporate costs. This increase was partially offset by labour efficiencies including implementation of the Automated Meter Reading strategy and an increase in contract labour for capital work.

Overtime in 2017 was higher than 2016 primarily due to restoration costs and normal labour inflation.

Contract labour for 2017 was higher than 2016 due to increased distribution work including distribution reliability initiatives and increased transmission line work.

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 2015 to 2017 are included in the table below:

Salary Cost Per FTE

	Actual 2017	Actual 2016	Actual 2015	Variance 2017-2016
Total reported internal labour costs	**$ 64,399**	$ 63,608	$ 63,330	$ 791
Benefit costs (net)	**(8,960)**	(8,470)	(7,559)	(490)
Other adjustments	**(1,171)**	(772)	(605)	(399)
Base salary costs	**54,268**	54,366	55,166	(98)
Less: executive compensation	**(2,016)**	(1,864)	(1,750)	(152)
Base salary costs (excluding executive)	**$ 52,252**	$ 52,502	$ 53,416	$ (250)
FTE's (including executive members)	**611.2**	634.5	653.0	
FTE's (excluding executive members)	**606.9**	630.5	649.0	
Average salary per FTE	**88,789**	85,683	84,481	
% increase	**3.62%**	1.42%	3.66%	
Average salary per FTE (excluding executive members)	**86,097**	83,271	82,305	
% increase	**3.39%**	1.17%	4.12%	

The above analysis indicates that the rate of increase in average salary per FTE for 2017 has increased from 2016 and is more in line with 2015.

Short Term Incentive (STI) Program

The following table outlines the actual results for 2015 to 2017 and the targets set for 2017:

Short Term Incentive (STI) Program

Measure	Target 2017	Actual 2017	Actual 2016	Actual 2015
Controllable Operating Costs/Customer	**$227.40**	$228.80	$219.70	$219.80
Earnings	**39.1m**	41.0m	40.0m	38.8m
Reliability - Duration of Outages (SAIDI)	**2.30**	2.28	2.24	2.36
Customer Satisfaction - % Satisfied	**86.1%**	86.5%	86.1%	86.1%
Injury Frequency Rate	**0.35**	0.18	0.4	0.18
Regulatory Performance	**Subjective**	120%	140%	140%

2017 STI results were adjusted to remove the impact of severe weather conditions in March and December. 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. For 2017, according to the company the key determinants of the result of 120% were as follows:

i. The Board's approval of the Company's:
   - 2018 Capital Budget Application in the 4th quarter
   - New net metering service option which was implemented on July 1, 2017
   - July 1st annual rate stabilization adjustment and flow-through of final rates resulting from Newfoundland and Labrador Hydro's (Hydro) 2013 amended General Rate Application ("GRA")
   - 2018 forecast average rate base and rate return on average rate base

ii. The Company's participation in Hydro's Board applications, which include:
   - Hydro's 2013 amended GRA, including the flow-through of final rates to the company's customers on July 1, 2017
   - Hydro's application to recover approximately $42 million in 2015 and 2016 fuel expenditures associated with its 120 MW combustion turbine
   - Hydro's 2018 Capital Budget Application
   - Hydro's ongoing 2017 GRA.

Further, according to the Company it refunded over $134 million (Inclusive of taxes) to its current and former customers. The refund arose from over collections in the Hydro rate stabilization plan ("RSP") for the period 2007 to 2013. By year end, 93% of the total RSP refund was disbursed by the Company.

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 2017 is established as a percentage of base pay for the three employee groups. For 2017, measures relating to 'Earnings', 'SAIDI', 'Customer Satisfaction', 'Safety', and 'Regulatory Performance' metrics were met, however, 'Controllable Operating Costs/Customer' metric fell below target.

The following table illustrates the target as a percentage of base pay, together with the actual STI payouts for 2015 to 2017:

	Target 2017	Actual 2017	Target 2016	Actual 2016	Target 2015	Actual 2015
President	50%	66.32%	50%	67.20%	50%	64.90%
Executive	40%	57.28%	40%	53.90%	40%	51.90%
Directors	15%	20.03%	15%	19.60%	15%	19.60%

STI actual payout rates for 'Executive' and 'Director' employee groups are higher than the prior year and each payout rate exceeded target consistent with 2016 and 2015.

In dollar terms, the STI payouts for 2015 to 2017 are as follows:

	Actual 2017	Actual 2016	Actual 2015	Variance 2017-2016
President	**$ 240,396**	$ 242,000	$ 227,000	$ (1,604)
Executive	**506,604**	442,000	401,000	64,604
Directors	**332,999**	323,300	342,200	9,699
Total	**$ 1,079,999**	$ 1,007,300	$ 970,200	$ 72,699
Year over Year % change	7.22%	3.82%	-0.77%	

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 2017, the non-regulated portion (before tax adjustment) was $301,080 (2016 - $367,818).

Executive Compensation

The following table provides a summary and comparison of executive compensation for 2015 to 2017.

	Base Salary	Short Term Incentive	Other	Total
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**
2015				
Total executive group	$ 1,122,000	$ 628,000	$ 106,244	$ 1,856,244
Average per executive (4)	**$ 280,500**	**$ 157,000**	**$ 26,561**	**$ 464,061**
% Average increase 2017 vs 2016	7.77%	9.21%	30.39%	10.70%
Per executive % average increase 2017 vs 2016	-0.4%	0.88%	16.98%	2.21%

Base salary, for the executive group in 2017 increased from 2016, in addition to general salary increases this overall increase in base salaries is primarily due to the appointment of a new CFO on February 7, 2017 with the previous CFO/COO not appointed to CEO until four months later on June 1st, 2017.

Other compensation for the executive group in 2017 increased from 2016, primarily due to an increase in the performance share unit payout received by each of the executives. STI payouts and performance share unit payouts were agreed to the Board of Directors' minutes.

Company Pension Plan

For 2017, we reviewed the accounts supporting the gross charge of $8,675,000 of pension expense for the Company. A detailed comparison of the components of pension expense for 2015 to 2017 and 2017 test year:

	Actual 2017	Test Year 2017	Actual 2016	Actual 2015	Variance 2017-2016
Pension expense per actuary	**$ 6,165,000**	**$ 4,823,000**	$ 7,330,000	$ 15,332,000	$ (1,165,000)
Pension uniformity plan (PUP)/supplemental employee retirement program (SERP)	**571,000**	**556,000**	557,000	562,000	14,000
Group RRSP @ 1.5%	**321,000**	**347,000**	350,000	384,000	(29,000)
Individual RRSP's	**1,640,000**	**1,906,000**	1,531,000	1,421,000	109,000
Less: Refunds (net of other expenses)	**(22,000)**	**(10,000)**	(5,000)	3,000	(17,000)
Total	**$ 8,675,000**	**$ 7,622,000**	$ 9,763,000	$ 17,702,000	$ (1,088,000)
Year over year percentage change	**(11.14%)**		(44.85%)	33.34%	

Overall, pension expense for 2017 is lower than 2016 primarily due to a decrease in the Company's projected benefit pension obligation. The decrease in obligation was due to a higher than expected return on plan assets, partially offset by a lower discount rate.

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 increased by 2.51% in 2017.

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 7.12% 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 $80,000 in overall RRSP contributions (Group and Individuals) made by the employer in comparison to 2016 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 2017 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 2015 to 2017 are as follows:

(000's)	Actual 2017	Test Year 2017	Actual 2016	Actual 2015	Variance 2017-2016
Accrued OPEBs	**$ 5,861**	$ 5,652	$ 6,089	$ 6,055	$ (228)
Amortization of transitional balance	**3,504**	3,504	3,504	3,504	-
Amount capitalized	**(1,001)**	(928)	(915)	(906)	(86)
Total	**$ 8,364**	$ 8,228	$ 8,678	$ 8,653	$ (314)

According to the company, the decrease in OPEBs expense from 2016 to 2017 is primarily due to a regulatory amortization that expired in August 2017.

Intercompany Charges

Our review of intercompany charges included the following specific procedures:

- assessed the Company's compliance with Order No. P.U. 19 (2003), Order No. P.U. 32 (2007), Order No. P.U. 43 (2009), and Order No. P.U. 13 (2013);
- compared intercompany charges for the years 2016 to 2017 and investigated any unusual fluctuations;
- reviewed detailed listings of charges for 2017 and investigated any unusual items;
- vouched a sample of transactions for 2017 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 2015 to 2017 for charges to and from Newfoundland Power Inc.:

	Actual 2017	Actual 2016	Actual 2015	Variance 2017-2016
Charges from related companies				
Regulated	**$ 225,084**	$ 153,602	$ 208,781	$ 71,482
Non-Regulated	**2,143,224**	2,293,715	1,672,009	(150,491)
Total	**$ 2,368,308**	$ 2,447,317	$ 1,880,790	$ (79,009)
Charges to related companies	**$ 2,206,966**	$ 329,339	$ 229,125	$ 1,877,627

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 over the first three quarters as well as its "true up" calculation for the 4th quarter. We noted during our review that Fortis Inc. continues to allocate its recoverable costs based on its subsidiaries' assets. There were no changes to the methodology in 2017.

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

During the fourth quarter of 2017, a "true up" calculation was completed to reflect actual recoverable expenses which were determined to be $2,002,000 and are summarized as follows:

2017 Recoverable Expenses from Fortis Inc.

	Amount	
Staffing and Staffing Related	$1,204,000	Non-regulated
Director Fees	202,000	Non-regulated
Consulting and Legal fees	111,000	Non-regulated
Trustee Agent Fees	26,000	Regulated
Audit and Other Fees	40,000	Non-regulated
2016 Recovery True Up	8,000	Non-regulated
Annual Meeting Expenses	50,000	Non-regulated
Travel (Board and Other)	67,000	Non-regulated
Insurance (D&O)	35,000	Non-regulated
Other Costs	259,000	Non-regulated
	2,002,000	
Less amounts previously billed:		
Q1 2017	591,000	
Q2 2017	535,000	
Q3 2017	433,000	
Q4 2017 balance owing	$ 443,000	

As detailed above, trustee agent fees for $26,000 were the only expenses allocated to regulated operations by the Company relating to recoverable expenses. Certain other direct costs were recovered by Fortis Inc. by separate invoicing throughout the year and 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 2015 to 2017 with Fortis Inc.:

Intercompany Transactions

(Regulated)	Actual 2017	Actual 2016	Actual 2015	Variance 2017-2016
Charges from Fortis Inc.				
Trustee fees and share plan costs	**$ 26,000**	$ 33,000	$ 35,000	$ (7,000)
Miscellaneous	**133,361**	53,059	24,472	80,302
Staff Charges	**-**	-	19,756	-
	$159,361	$ 86,059	$ 79,228	$ 73,302
Year over year percentage change	**85.18%**	8.62%	(55.14%)	
Charges to Fortis Inc.				
Printing and stationery	**$ -**	$ -	$ 2,191	$ -
Postage and couriers	**4,113**	7,583	19,468	(3,470)
Staff charges	**43,581**	38,282	44,430	5,299
Staff charges - insurance	**-**	550	4,639	(550)
IS Charges	**5,888**	-	-	5,888
Pole removal and installation	**93**	138	-	(45)
Miscellaneous	**49,406**	16,895	7,855	32,511
	$103,081	$ 63,448	$ 78,583	$ 39,633
Year over year percentage change	**62.47%**	(19.26%)	(54.70%)	

According to Newfoundland Power, regulated charges from Fortis Inc. are generally not based on specific allocation percentages and instead are invoiced based on actual costs or based on Newfoundland Power's usage of a specific service.

The most significant fluctuations from our analysis of regulated charges from Fortis Inc. is an increase in the miscellaneous account of $80,302. This is primarily the result of a one-time SERP payment of $45,577 and a pension expense of $45,531.

The most significant fluctuation from our analysis of regulated charges to Fortis Inc. is a $32,511 increase in the miscellaneous account. This is primarily a result of a Performance Share Unit (PSU) Grant of $30,967.

The following table provides a summary and comparison of the non-regulated intercompany transactions for 2015 to 2017:

(Non-Regulated)	**Actual 2017**	**Actual 2016**	**Actual 2015**	**Variance 2017-2016**
Charges from Fortis Inc.				
Director's fees and travel	**202,000**	231,000	166,000	(29,000)
Staff charges	**1,204,000**	1,293,000	944,000	(89,000)
Miscellaneous[i]	**732,811**	769,715	562,009	(36,904)
	$ 2,138,811	$ 2,293,715	$ 1,672,009	$ (154,904)
Charges from Maritime Electric				
Miscellaneous	**$ 4,413**	$ -	**$ -**	$ 4,413
	$2,143,224	$ 2,293,715	$ 1,672,009	$ (150,491)

[i]Miscellaneous includes annual and quarterly report fees.

Staff charges decreased by $89,000, primarily due to a decrease in Newfoundland Power's percentage allocation of Fortis Inc. corporate costs due to the acquisition of ITC in October 2016, with full year impact experienced in 2017.

Miscellaneous charges from Fortis Inc. decreased by $36,904, primarily due to a decrease in PSU Grant due to a retirement in late 2017.

The following table provides a summary and comparison of the other intercompany transactions for 2015 to 2017:

Intercompany Transactions (Other)	**Actual 2017**	**Actual 2016**	**Actual 2015**	**Variance 2017-2016**
Charges to Fortis Properties				
Staff charges	**$ -**	$ -	$ 23,569	$ -
Staff charges - insurance	**-**	2,950	21,796	(2,950)
Miscellaneous	**-**	-	500	-
	$ -	$ 2,950	$ 45,865	$ (2,950)
Charges from Fortis Properties				
Hotel/Banquet facilities & meals	**$ -**	$ -	$ 3,113	$ -
Miscellaneous	**-**	-	48,885	-
	$ -	$ -	$ 51,998	$ -
Charges to Fortis Ontario Inc.				
Staff charges	**$ 138,200**	$ 22,698	$ 3,620	$ 115,502
Staff charges - insurance	**-**	1,794	5,666	(1,794)
IS charges	**-**	-	4,065	-
Miscellaneous	**1,703**	400	390	1,303
	$ 139,903	$ 24,892	$ 13,741	$ 115,011
Charges to Maritime Electric				
Staff charges	**$ 3,719**	$ 34,749	$ 6,541	$ (31,030)
Staff charges - insurance	**-**	756	934	(756)
IS charges	**-**	-	3,048	-
Miscellaneous	**550**	530	530	20
	$ 4,269	$ 36,035	$ 11,053	$ (31,766)
Charges from Maritime Electric				
Miscellaneous	**16,713**	2,880	250	13,833
Charges from Central Hudson Gas & Electric				
Miscellaneous	**$ 8,034**	$ 3,538	$ 182	$ 4,496

Intercompany Transactions (Other) Cont'd.	Actual 2017	Actual 2016	Actual 2015	Variance 2017-2016
Charges to Belize Electric Company Ltd.				
Staff charges	**$ 112,387**	$ 121,021	$ 20,779	$ (8,634)
Miscellaneous	**845**	1,793	-	(948)
	$ 113,232	**$ 122,814**	**$ 20,779**	$ (9,582)
Charges to FortisAlberta Inc.				
Staff charges - insurance	**$ -**	$ -	$ 39	$ -
Miscellaneous	**4,740**	4,510	4,260	230
	$ 4,740	$ 4,510	$ 4,299	$ 230
Charges from FortisAlberta Inc.				
Miscellaneous	**$ 37,611**	$ 44,744	$ 49,452	$ (7,133)
Charges to FortisBC Inc./ Fortis BC Holdings				
Staff Charges	**$ 11,578**	$ -	$ 39	$ 11,578
IS charges	**-**	-	10,363	-
Miscellaneous	**9,310**	9,240	9,190	70
	$ 20,888	$ 9,240	$ 19,592	$ 11,648
Charges from FortisBC Inc./ FortisBC Holdings				
Miscellaneous	**$ 3,365**	$ 7,359	$ 3,822	$ (3,994)
Charges to Caribbean Utilities Co. Limited				
Staff charges	**$ 4,240**	$ 30,111	$ 22,219	$ (25,871)
Charges from Caribbean Utilities Co. Limited				
Miscellaneous	**$ -**	$ 9,022	$ 23,849	$ (9,022)
Charges to Fortis Turks and Caicos				
Staff charges	**$ 698,896**	$ 32,289	$ 12,271	$ 666,607
Miscellaneous	**1,117,717**	3,050	723	1,114,667
	$ 1,816,613	$ 35,339	$ 12,994	$ 1,781,274

The most significant fluctuations from our analysis of other intercompany charges for 2017 compared to 2016 are as follows:

- Staff charges to Fortis Ontario Inc. increased by $115,502, primarily due to a NL Power employee's secondment to Fortis Ontario.
- Staff charges to Maritime Electric decreased by $31,030, which reflects the labour and travel time charged to Maritime Electric during the transition period where a new Vice President assumed the position of VP, Customer Service in April 2016 and there were more charges in 2016 related to the transition.
- Staff charges to Caribbean Utilities Co. Limited decreased by $25,871 due to an employee who supplied service pertaining to transportation requirements as well as expenses incurred by an employee who was on the Board of Directors in 2016.
- Staff charges to Fortis Turks and Caicos increased by $666,607, which is a direct result of Newfoundland Power's Hurricane Team's power restoration efforts after Hurricane Irma.
- Miscellaneous Charges to Fortis Turks and Caicos increased by $1,114,667 which is a direct result of Newfoundland Power's Hurricane Team's power restoration efforts after Hurricane Irma. $1,045,954 was for 398 transformers, transformer accessories and freight during restoration efforts, and the remainder was travel expenses, vaccinations and supplies for the Newfoundland Power's Hurricane team.

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 2017 and vouching of a sample of individual transactions to supporting documentation.

(000's)	Actual 2017	Actual 2016	Actual 2015	Variance 2017-2016
Other company fees				
Other company fees	$ 3,082	$ 2,092	$ 1,601	$ 990
Regulatory hearing costs	(786)	852	1,156	(1,638)
	$ 2,296	$ 2,944	$ 2,757	$ (648)
Year over year percentage change	-22.0%	6.8%	4.0%	
Deferred regulatory costs				
Total deferred regulatory costs	$ 341	$ 172	$ 322	$ 169
Year over year percentage change	98.3%	-46.6%	0.0%	

Other Company Fee costs for 2017 were lower than 2016. According to the Company, this is due primarily to a reduction in estimated liability for third party costs associated with the investigation by the Public Utilities Board into power outages and supply issues that commenced in 2014 and are ongoing. The variance to 2016 was partially offset by increased consultant costs for customer energy conservation programming, cyber security, and engineering studies. 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 2015 to 2017 is as follows:

(000's)	Actual 2017	Actual 2016	Actual 2015	Variance 2017-2016
Miscellaneous	**$ 1,117**	$ 1,082	$ 967	$ 35
Cafeteria and lunchroom Supplies	**84**	89	84	(5)
Promotional items	**199**	193	152	6
Computer Software	**2**	1	2	1
Damage claims	**216**	196	301	20
Community relations activities	**3**	3	3	-
Donations and charitable advertising	**217**	202	188	15
Books, magazines and subscriptions	**7**	21	35	(14)
Misc. lease payments	**34**	34	33	-
Total miscellaneous expenses	**$ 1,879**	$ 1,821	$ 1,765	$ 58
Year over year percentage change	**3.19%**	3.17%	-10.45%	

Miscellaneous expenses by their very nature can fluctuate from year to year. From 2016 to 2017 these expenses have increased by 3.19% overall.

Our procedures in this expense category for 2017 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 2017 expenses are unreasonable.

Conservation and Demand Management (CDM)

In compliance with Order No. P.U. 7 (1996-97), the Company filed the 2017 Conservation and Demand Management Report with the Board. This report provided a summary of 2017 CDM activities and costs as well as the outlook for 2017.

In 2015, 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 2017, the Utilities implemented the principal changes to customer conservation programming contained in the 2016 Plan. These changes relate to (i) expansion of current programs, particularly for commercial customers; (ii) removal of alliance and electronics rebate program; and (iii) ongoing initiatives to educate customers about heat pumps, including a partnership with the government of Newfoundland and Labrador to offer reduced interest financing to eligible customers.

Total CDM costs in 2017 totaled $7,865,000 compared to $8,039,000 in 2016, a $174,000 decrease. Conservation costs are lower than in 2016 as 2016 included increased customer uptake on instant rebates for items offering energy savings such as LED light bulbs.

In 2017, $6,758,000 ($4,731,000 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 2017 and 2016.

(000's)	Actual 2017	Actual 2016	Actual 2015	Variance 2017-2016
Vehicle expense	1,854	1,797	1,786	57
Operating materials	1,528	1,425	1,583	103
Inter-company charges	2,002	2,145	1,560	(143)
Plants, Subs, System Oper & Bldgs	2,796	2,770	2,367	26
Travel	1,235	1,160	1,052	75
Tools and clothing allowance	1,234	1,161	1,130	73
Conservation	2,981	4,253	2,466	(1,272)
Taxes and assessments	1,252	1,214	1,123	38
Uncollectible bills	1,386	1,194	1,313	192
Insurance	1,326	1,293	1,260	33
Severance & other employee costs	102	47	72	55
Education, training, employee fees	339	275	298	64
Trustee and directors' fees	489	471	426	18
Stationary & copying	214	266	230	(52)
Equipment rental/maintenance	806	838	746	(32)
Communications	2,927	2,959	3,184	(32)
Advertising	1,592	1,519	1,251	73
Vegetation management	2,099	1,820	1,766	279
Computing equipment & software	1,451	1,359	1,058	92
Transfers (GEC)	(2,847)	(2,955)	(3,809)	108
CDM amortization	2,741	1,712	1,053	1,029

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

- Conservation costs in 2017 were lower than 2016 as 2016 included customer uptake of customer energy conservation incentives instant rebate campaign.
- Uncollectible bills were higher in 2017 than 2016 reflecting higher AR balances.
- Vegetation management costs for 2017 were higher than 2016 due to increased vegetation management activity for distribution, transmission lines, and substations reflecting favorable weather conditions.
- Amortization of Deferred CDM costs commenced in 2014 and is higher in 2017 due to the inclusion of the fourth year of deferred customer energy conservation programming costs.

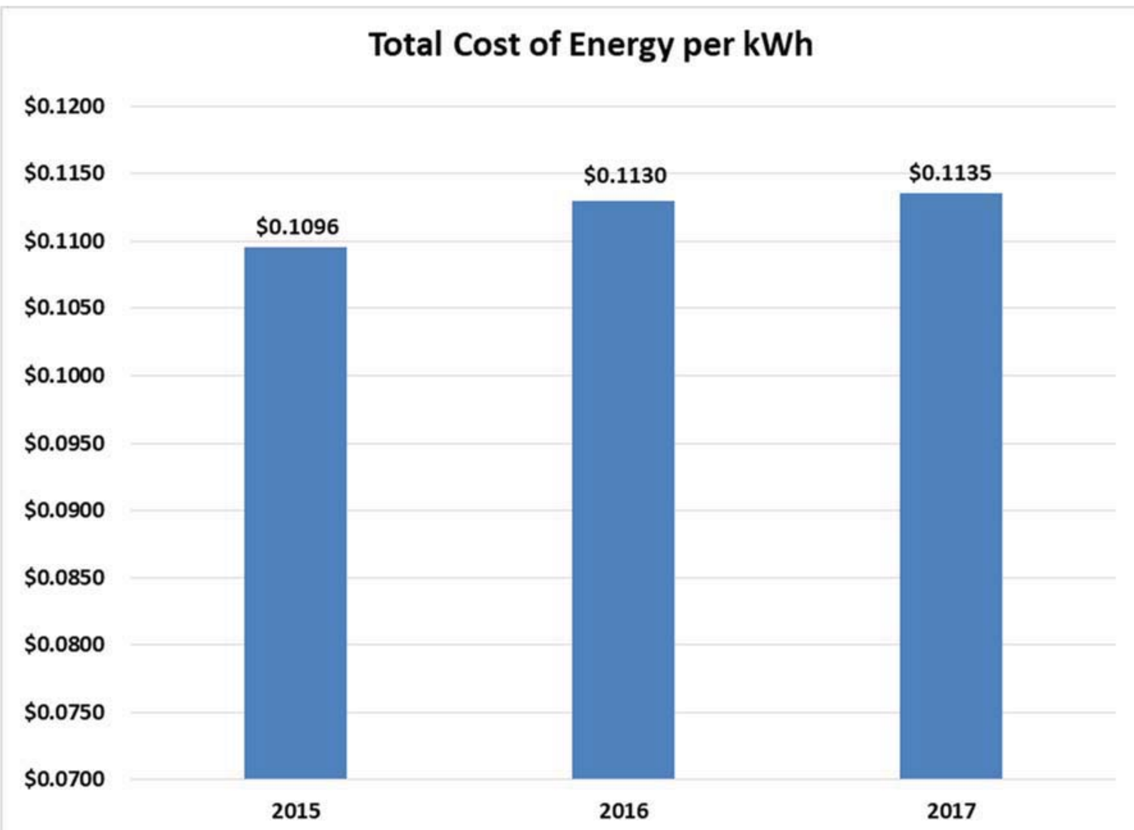
Other Costs

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 2015 to 2017:

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
2015	5,956,600	$ 84,046	$ 422,095	$ 3,990	$ 56,720	$ 35,724	$ 10,925	$ 39,314	$ 652,814	$ 0.1096
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



Purchased Power

We have reviewed the Company's purchased power expense for 2017 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 $3.1 million, from $443.3 million in 2016 to $440.2 million in 2017. According to the Company, the decrease in costs were lower in 2017 due to lower energy purchases partially offset by higher demand charges from Hydro.

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 2017 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 2017; and,
- assessed the overall reasonableness of the depreciation for 2017.

Amortization expense for 2017 is $62,973,000 as compared to $60,472,000 for 2016, representing a 4.1% increase. The 2017 and 2016 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)	2017	2016	Variance 2017-2016	%
Depreciation and amortization as reported	$ 62,973	$ 60,472	$ 2,501	**4.1%**
Less: Tax on Cost of Removal (1)	(5,486)	(5,282)	(204)	**3.9%**
Depreciation of Fixed Assets	$ 57,487	$ 55,190	$ 2,297	**4.2%**

Note 1: Recognized as income tax for financial reporting purposes

The following table provides a comparison of the depreciation of fixed assets for 2017, 2016 and 2015:

($000's)	2017	2016	2015	Variance 2017-2016	Variance 2016-2015
Depreciation of Fixed Assets	$ 57,487	$ 55,190	$ 51,851	$ 2,297	$ 3,339

Depreciation of fixed assets for 2017 is $57,487,000 as compared to $55,190,000 for 2016, representing a 4.2% increase. The change is attributable to an increase of depreciable assets by approximately $63,366,000.

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 2017.

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 2015 to 2017:

(000's)	**Actual 2017**	**Actual 2016**	**Acutal 2015**	**Variance 2017-2016**
Interest				
Long-term debt	**$ 35,013**	$ 34,846	$ 35,020	167
Other	**672**	878	1,139	(206)
Amortization				
Debt discount	**234**	223	242	11
Interest charged to construction	**(554)**	(712)	(677)	158
Total Finance charges	**$ 35,365**	$ 35,235	$ 35,724	130
Year over year percentage change	**0.37%**	-1.37%	-1.99%	

In the above table, finance charges increased by approximately $0.13 million, from $35.2 million in 2016 to $35.4 million in 2017. According to the company, the increase was due to the combination of (i) interest costs associated with the issuance of $75 million, 3.815% first mortgage sinking fund bonds in June 2017, (ii) the maturity of $30.4 million, 10.9% first mortgage sinking fund bonds in May 2016, and (iii) lower facility borrowings.

Based upon our analysis, nothing has come to our attention to indicate that the finance charges for 2017 are unreasonable.

Income Tax Expense

We have reviewed the Company's income tax expense for 2016 and have noted that the effective income tax rate increased from 22.6% in 2016 to 23.7% in 2017. 2017 and 2016 results in the following effective rates:

	2017	2016	2015	2017-2016
Income tax expense	$ 12,882	$ 11,851	$ 10,925	$ 1,031
Earnings before income tax	$ 54,408	$ 52,359	$ 50,239	$ 2,049
Effective income tax rate	23.7%	22.6%	21.7%	1.1%

Income tax expense increased by $1,031,000 compared to 2016. The increase is due to higher pre-tax earnings and an increase in the effective tax rate from 22.6% to 23.7%. The statutory tax rate was 30.0% for both 2017 and 2016.

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 2017 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 $424,674 for the current period compare to a total of $349,974 for the same period during the previous year. The credit total for the 2016-2017 winter season is higher than the previous season total primarily due to higher contracted load curtailment. There were 23 option participants in 2016-2017, compared to 18 participants in the previous year.

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 2017 to prior years and investigated any unusual fluctuations;
* reviewed detailed listings of expenses for 2017 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 2017	Actual 2016	Actual 2015		Variance 2017-2016
Charged from Fortis Companies	**2,121,500**	2,249,100	1,672,000		(127,600)
Performance and restricted share units	**687,500**	454,500	276,800		233,000
Donations and charitable advertising	**301,700**	283,300	273,700		18,400
Executive short term incentive	**361,900**	341,000	272,600		20,900
Miscellaneous	**45,000**	70,200	39,100		(25,200)
	3,517,600	3,398,100	2,534,200	-	119,500
Less: Income Taxes	**1,055,300**	1,019,400	734,900		35,900
Total non-regulated (net of tax)	**$ 2,462,300**	**$ 2,378,700**	**$ 1,799,300**		$ 83,600

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 2017 this represents an addition to non-regulated expenses (before tax adjustment) of $361,900 (2016 - $341,000). 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 2017 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 2016 and 2017:

(000's)	2017 Actual	2016 Actual	Variance 2017-2016
Regulatory Assets			
Rate stabilization account	**$ 4,519**	$ 4,763	$ (244)
OPEBs asset	**28,032**	31,536	(3,504)
Deferred GRA costs	**341**	682	(341)
Conservation and demand management deferral	**20,017**	15,999	4,018
Demand management incentive	**2,128**	-	2,128
Employee future benefits	**82,732**	100,757	(18,025)
Weather normalization account	**6,815**	2,458	4,357
Deferred income taxes	**207,207**	191,313	15,894
	$ 351,791	$ 347,508	$ 4,283
Regulatory Liabilities			
Rate stabilization account	**$ 4,254**	$ -	4,254
Cost recovery deferral	**1,032**	2,064	(1,032)
Future removal and site restoration provision	**151,975**	143,419	8,556
	$ 157,261	$ 145,483	$ 11,778

<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, 2017 were approved by the Board in Order No. P.U. 23 (2017).

As of December 31, 2017, there was a charge to the RSA of $7,292,557 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. 23 (2017).

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, 2017, the credit balance of $114,060 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 GAAP 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, 2017, the balance of $1,167,213 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. As of March 31, 2017 $2,458,149 was credited to the RSA in accordance with Order No. P.U. 13 (2013).

The RSA is also adjusted for the Demand Management Incentive Account ($Nil balance in 2016 therefore no impact on RSA in 2017) 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 Canadian Generally Accepted Accounting Principles ("GAAP"). 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 2017.

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, 2017 were $20,017,000 with amortization of $2,740,556 in 2017.

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 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

The Company's Application included a comparison between the actual opening regulatory assets and liabilities as of January 1, 2012 related to employee future benefits which created a regulatory asset 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).

In Order No. P.U. 11 (2012) the Board approved the creation of a regulatory asset to reflect the accumulated difference to December 31, 2012 in defined benefit pension expense calculated under US GAAP and Canadian Generally Accepted Accounting Principles. In Order No. P.U. 13 (2013) the Board approved the recognition of defined pension expense in accordance with U.S GAAP and a regulatory asset of $12,400,000, resulting from Order No. P.U. 11 (2012), to be amortized over 15 years commencing in 2013.

As of December 31, 2017 the regulated asset for employee future benefits was $82,732,000.

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. 11 (2018) the Board approved the December 31, 2017 net regulatory asset balance in the Weather Normalization Account of $6,815,000 ($4,770,830 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, 2017 was $207,207,000.

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 $1,548,000 over 2016 and 2017, resulting in a net regulating liability of $1,032,000 as at December 31, 2017.

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 2017 the balance in this account was $151,975,000 (2016 - $143,419,000).

Based upon our analysis, nothing has come to our attention to indicate that changes in regulatory deferrals for 2017 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 generally accepted accounting principles 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 2017 PEVDA was calculated at $1,167,213. This balance was transferred to the Rate Stabilization Account as a charge on March 31, 2017 in accordance with Order No. P.U. 43 (2009).

We confirm that the 2017 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 generally accepted accounting principles 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 2017 OPEBVDA was calculated at $114,060. This balance was transferred to the Rate Stabilization Account as a charge on March 31, 2017 in accordance with Order No. P.U. 31 (2010).

We confirm that the 2017 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 2017 are as follows:

1. Made capital investments of $91 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 and the Substation Modernization Plan.

4. The installation of Automated Meter Reading (AMR) meters was substantially complete by year end. In 2017, the company has installed over 44,000 meters and reduced a total of 152 routes through optimization. Implementation of AMR meters has allowed the company to realize significant operating efficiencies in customer metering. Over the 5 years ending in 2017, annual meter reading operating costs per customer have been reduced by approximately 2/3rds from $12.56 to $4.16.

5. Continued the Substation Modernization and Refurbishment program. In total 87% of the distribution feeders are now automated.

6. Continued to install down line reclosers to provide for improved control of the distribution system.

7. An email promotion conducted in the 4th quarter resulted in an additional 2,259 new accounts being enrolled in the e-bills program. Over 113,000 customers were enrolled in e-Bills at year-end. This represents approximately 44% of all billed customers.

8. Newfoundland Power and the Provincial Department of Environment and Climate Change finalized a more streamlined blanket permitting system. The new consolidated permit ensures that day to day operations are within environmental guidelines and cover topics such as fording bodies of water, protected public water supply areas and pole placements near water bodies.

9. A new phone call handling technology was implemented in the Customer Contact Centre. The new system from Avaya is performing as intended and has enabled a number of improvements to call forecasting and staff scheduling. It was effective in supporting response to a high volume of calls within an hour of its implementation on May 1, when over 21,000 customers were left without power following a loss of supply from Hydro. In the 3rd quarter, enhancements will include implementation of an email management module.

10. In September, the company implemented an improved process for handling customer emails within the Customer Contact Centre. The Avaya system now permits Customer Service Representatives to switch from customer telephone response to email response directly within a single software application. This technological refinement enables Customer Service Representatives to more efficiently respond to customers.

11. Installed remote computer terminals at Corner Brook and Burin offices which allow customers to directly talk to a CSR in St. John's and Clarenville.

12. Upgraded mobile maintenance inspection application and integrated it with the Company's GIS system.

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 2015	Actual 2016	Actual 2017	Plan 2017	Measure Achieved
Reliability	Outage Hours/Customer (SAIDI) – excluding Hydro loss of supply[1]	2.36	2.24	2.28	2.30	Yes
	Outage/Customer (SAIFI) – excluding Hydro loss of supply[1]	2.11	1.36	1.66	1.87	Yes
	Plant Availability (%)[2]	94.9	85.3	91.3	96.0	No
Customer Satisfaction	% of Satisfied Customers as measured by Customer Satisfaction Survey	86.0	86.0	86.5	87.0	No
	Call Centre Service Level (% per second)	82/60	81/60[4]	80/60	80/60	Yes
	Trouble Call Responded to Within 2 Hours (%)	86.0	87.0	87.0	85.0	Yes
Safety	All Injury/Illness Frequency Rate	0.5	1.3	0.7	0.9	Yes
Financial	Earnings (millions)[3]	$38.8	$40.0	$41.0	$39.1	Yes
	Gross Operating Cost/Customer[3]	$249	$260	$264	$269	Yes

[1] 2016 reliability statistics exclude the impact of a wind storm in December. 2017 reliability statistics exclude the impact of a snow storm in December and a snow storm in March.
[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.
[4] 82/60 per Q4 Quarterly Regulatory Report. Difference does not impact whether the measure was achieved in 2016.

The following table compares whether the company measures were achieved during the 2015, 2016, and 2017 years:

Category	Measure	Measure Achieved 2015	Measure Achieved 2016	Measure Achieved 2017
Reliability	Outage Hours/Customer (SAIDI) – excluding Hydro loss of supply	Yes	Yes	Yes
	Outage/Customer (SAIFI) – excluding Hydro loss of supply	No	Yes	Yes
	Plant Availability (%)	No	No	No
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	Yes	No	Yes
Financial	Earnings (millions)	Yes	Yes	Yes
	Gross Operating Cost/Customer	Yes	Yes	Yes

Grant Thornton
2018 Annual Financial Review of Newfoundland Power Inc.

Board of Commissioners of Public Utilities

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

Table of Contents

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.

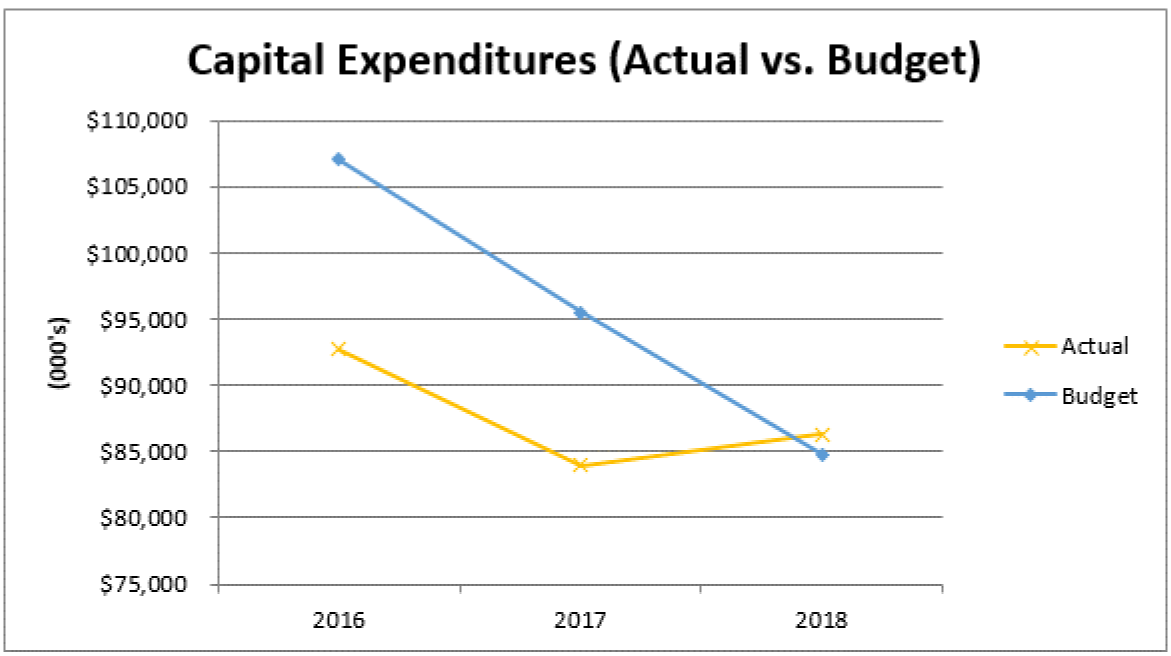
Capital Expenditures

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.

Capital Expenditure Reports

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

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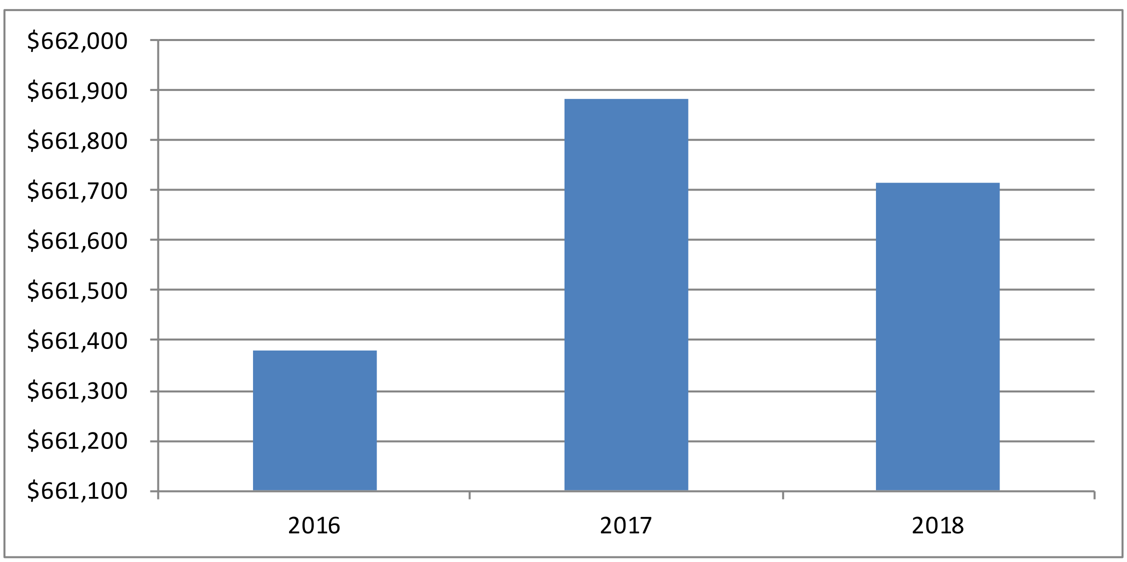
Revenue from rates

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)

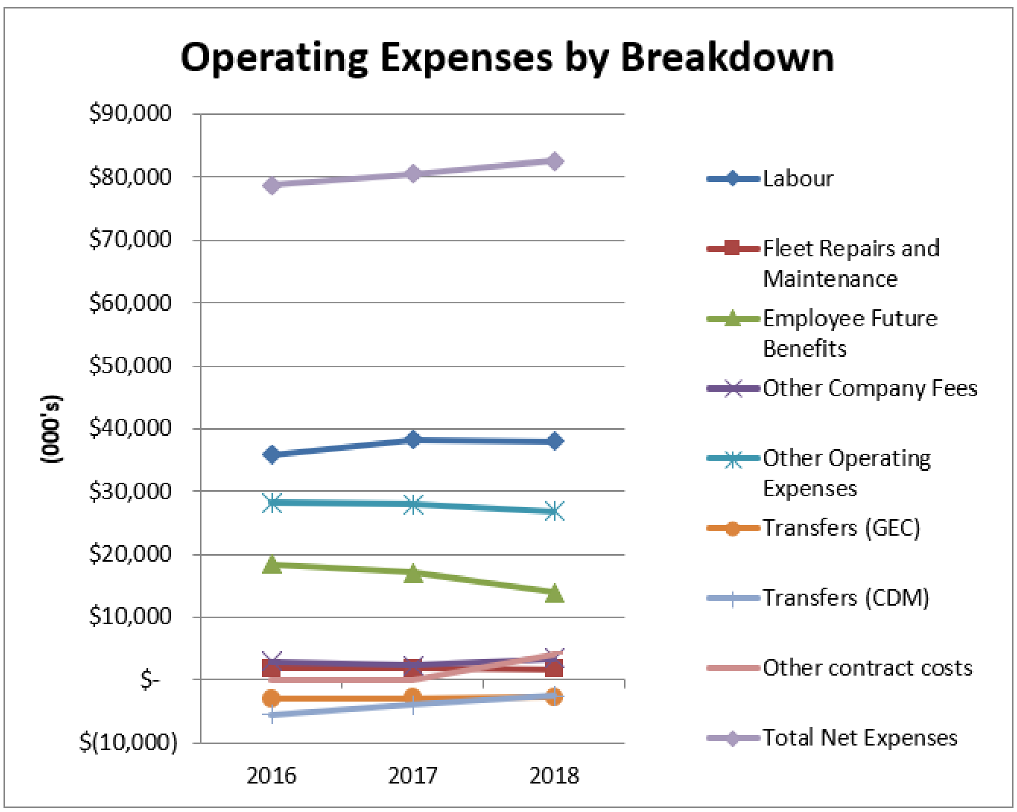
Note 1: According to the company, the presentation of other revenue was changed to be on a gross basis in 2018. This resulted in an increase in revenue and operating costs in 2018 related to work for telecommunciation companies. The 2017 and 2016 comparative have not been restated for this change in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

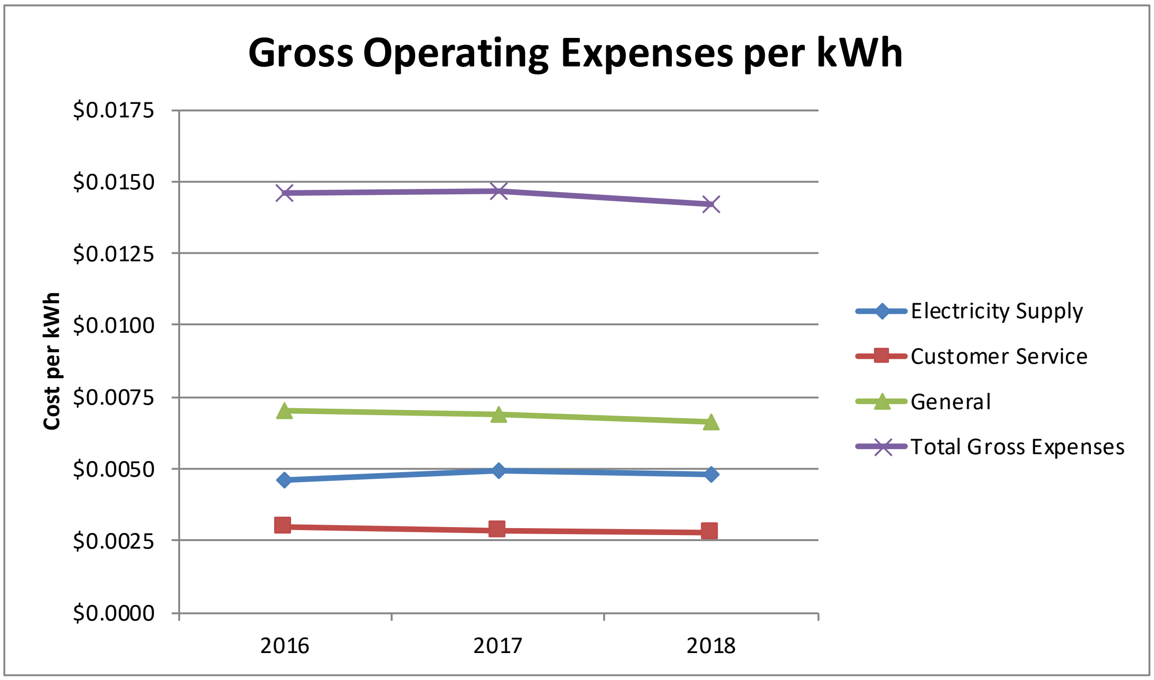
Our detailed review of operating expenses was conducted using the breakdown as documented in the above table. It should also be noted that our review is based upon gross expenses before allocation to GEC and CDM. The following table and graph show the trend in operating expenses by breakdown for the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

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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.

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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.

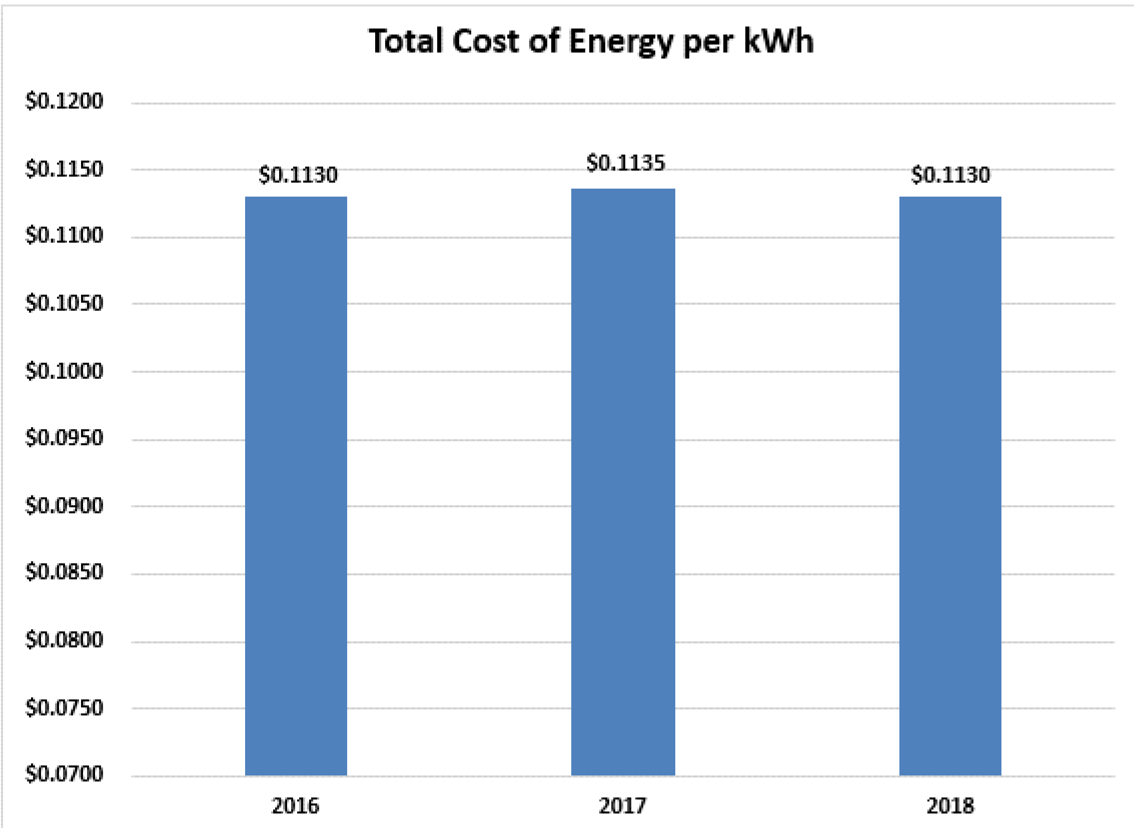
Other Costs

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).

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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

Grant Thornton
2019 Annual Financial Review of Newfoundland Power Inc.

Board of Commissioners of Public Utilities

Financial Consultants Report
2019 Annual Financial Review of
Newfoundland Power Inc.

Table of Contents

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 2019 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 Access to Information and Protection of Privacy Act 2015 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 2019 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 2019 was $1,153,556,000 which is an increase of $36,215,000 (3.24%) over the average rate base for 2018 of $1,117,341,000. The Company's calculation of the return on average rate base for 2019 was 6.97% (2018 – 7.13%) compared to an approved rate of return of 7.01%. The actual rate of return was within the range approved by the Board (6.83% to 7.19%). 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 2019 was $510,388,000 (2018 - $495,374,000). The Company's actual return on average common equity for the year ended December 31, 2019 was 8.79% (2018 – 8.76%). 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, the Company must file a report with its annual return explaining the facts and circumstances contributing to the difference. In 2019 the cost of common equity was 8.50% as per Order No. P.U. 2 (2019). The actual return on average common equity for 2019 was 8.79% 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 2.5% over budget in 2019. The capital expenditures were over the approved budget (including projects carried over from prior years) on a net basis by $6,145,000 (5.21%). However, for each category of expenditure, the variances ranged from an over-budget of 55.08% to an under-budget of 100.00%.

The Company experienced a 3.39% increase in revenue from rates in 2019 as compared to 2018. The increase is primarily due to the flow through of higher wholesale electricity rates effective July 1, 2018. This increase is offset due to lower electricity sales of 29.5 GWh compared to 2018 due to lower average consumption by residential customers.

Overall, net operating expenses decreased by $3,379,000 from 2018 to 2019. 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 2019 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 2019 Pension Expense Variance Deferral Account (PEVDA) operated in accordance with Order No. P.U. 43 (2009).

Based on our review, the 2019 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 2019 the Company met seven out of nine of its planned performance measures. The Company fell short of its targets in "Call Centre Service Level" and "Trouble Call Responded to Within 2 Hours".

Introduction

This report to the Board of Commissioners of Public Utilities presents our observations, findings and recommendations with respect to our 2019 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;
   - amortization of regulatory costs;
   - 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, and
   - travel.

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 2019 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 2014 Depreciation Study 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, 2019 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 12, 2020. 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 27, 2020, the Company filed a revised system of accounts as part of its 2019 Annual Report. In submitting these changes, the Company noted that the revisions were mainly due to the addition of three new accounts and some minor wording changes to improve the clarity and accuracy of account descriptions.

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, 2019 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 2019 was $1,153,556,000 which is an increase of $36,215,000 (3.24%) over the average rate base for 2018 of $1,117,341,000. 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 2019; 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 2018 and 2019 (all figures shown are averages):

(000)'s	2019	2018
Net Plant Investment (average)		
Plant Investment	$1,909,493	$1,834,415
Accumulated Depreciation	(771,588)	(739,030)
CIAC's	(41,596)	(38,474)
	1,096,309	1,056,911
Additions to Rate Base (average)		
Deferred Charges (a)	90,842	90,963
Cost Recovery Deferral for Hearing Costs (b)	247	171
Cost Recovery Deferral – Conservation (c)	16,630	15,003
Customer Finance Programs (d)	2,477	1,978
Demand Management Incentive Account (e)	941	745
Weather Normalization Reserve (f)	3,586	3,144
	114,723	112,004
Deductions from Rate Base (average)		
Other Post-Employment Benefits (g)	59,452	54,848
Customer Security Deposits (h)	1,245	1,069
Accrued Pension Obligation (i)	5,060	5,294
Deferred Income Taxes (j)	7,488	4,401
Cost Recovery Deferral (k)	613	362
	73,858	65,974
Average Rate Base before Allowances	1,137,174	1,102,941
Rate Base Allowances		
Materials and Supplies	6,475	6,184
Cash Working Capital	9,907	8,216
	16,382	14,400
Average Rate Base	$1,153,556	$1,117,341

(a) The Company's rate base is determined using the ARBM which incorporates average deferred charges into the calculation of rate base. The total average deferred charges of $90,842,000 (2018 - $90,963,000) included in the 2019 rate base consists of average deferred pension costs of $90,751,000 (2018 - $90,848,000) and credit facility costs of $91,000 (2018 - $115,000). The Company has included a schedule of these costs in Return 8.

(b) In Order No. P.U. 2 (2019) the Board approved the 34-month amortization of $1,000,000 in estimated hearing costs related to the 2019/2020 General Rate Application, commencing March 1, 2019 through December 31, 2021. According to the Company, the actual hearing costs for the 2019/2020 General Rate Application were $329,728. The Company transferred $670,272 to the Rate Stabilization Account on March 31, 2019 representing the difference between actual of $329,728 and estimated costs of $1,000,000 as directed by the Board in Order No. P.U. 2 (2019) instead of a reduction in rate base in 2019. The 2019 average rate base includes an addition of $247,000 relating to these hearing costs.

(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 2019. The actual costs incurred and deferred in 2019 were $6,864,000 ($4,805,000 after tax) resulting in additional annual amortization of $686,000 to commence in 2020. Included in the calculation of the average rate base for 2019 is $16,630,000 (2018 - $15,003,000) 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 2019 average rate base incorporates $2,477,000 (2018 - $1,978,000) related to these programs.

(e) The 2018 balance of the Demand Incentive Account was $Nil as there was no supply cost variance outside the dead band. In Order No P.U. 11 (2020) the Board approved the disposition of the 2019 balance of the Demand Incentive Account of $2,687,000 ($1,881,000 after tax) by means of a debit to the Rate Stabilization Account as of March 31, 2020. The 2019 average rate base incorporates $941,000 (2018 - $745,000) related to this account.

(f) During 2019, 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 $1,517,000 in 2019 (2018 – $4,771,000 increase).

Other transfers:

i. $1,347,000 transfer decrease (2018 – $90,000 decrease) to the reserve related to the after tax impact of the Degree Day Normalization Reserve Transfer.
ii. $4,307,000 transfer decrease (2018 - $1,427,000 decrease) to the reserve related to the after tax impact of the Hydro Production Equalization Reserve transfer.

The net impact was a net increase to the reserve of $4,137,000 (2018 - $3,254,000 decrease). The ending balance in this reserve account totaled ($5,654,000) compared to a balance of ($1,517,000) at December 31, 2018 (an average of ($3,586,000) for 2019) (2018 – ($3,144,000)). This represents a balance to be recovered from customers.

(g) Other Post-Employment Benefits is equal to the difference, at December 31, 2019, between the OPEBs liability of $92,026,000 and the OPEBs asset of $30,235,000. The calculation of the 2019 average rate base of $59,452,000 is equal to the average of the December 31, 2019 net liability of $61,791,000 and the December 31, 2018 net liability of $57,112,000.

(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 2019 average rate base incorporates $1,245,000 (2018 - $1,069,000) related to customer security deposits.

(i) The 2019 average rate base calculation incorporates $5,060,000 (2018 - $5,294,000) 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 2019 average rate base is ($2,954,000) and ($15,636,000) respectively. The remaining balance of the deferred income tax liability in the amount of $26,078,000 relates to capital assets. This results in an average balance for deferred income tax liability of $7,488,000 (2018 - $4,401,000).

(k) In Order No. P.U. 2 (2019) the Board approved the deferral over a 34-month period of a $2,482,000 (before tax) over-recovery of revenue from March 1, 2019 rate implementation of rates. The 2019 average rate base includes deduction of $613,000 (2018 - $362,000).

The net change in the Company's average rate base from 2018 to 2019 can be summarized as follows:

(000's)	**2019**	2018
Average rate base - opening balance	**$ 1,117,341**	$ 1,092,254
Change in average deferred charges and deferred regulatory costs	**1,332**	139
Average change in:		
Plant in service	**75,078**	61,539
Accumulated depreciation	**(32,558)**	(29,045)
Contributions in aid of construction	**(3,122)**	(1,241)
Weather normalization reserve	**442**	(102)
Other post-employment benefits	**(4,604)**	(5,515)
Future income taxes	**(3,087)**	(1,351)
Rate base allowances	**1,982**	110
Customer Finance Programs	**499**	559
Demand Management Incentive Acct	**196**	-
Other rate base components (net)	**57**	(6)
Average rate base - ending balance	**$ 1,153,556**	$ 1,117,341

Based upon the results of the above procedures we did not note any discrepancies in the calculation of the 2019 average rate base, and therefore conclude that the 2019 average rate base included in the Company's annual report to the Board is 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 2019 was 6.97% (2018 – 7.13%). 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 2019, the return on average rate base is calculated in accordance with the methodology approved in Order No. P.U. 2 (2019).

The actual return on average rate base in comparison to the range of allowed return for each of the years from 2017 to 2019 is set out in the table below.

	2019	2018	2017
Actual Return on Average Rate Base	6.97%	7.13%	7.22%
Upper End of Range set by the Board	7.19%	7.22%	7.37%
Lower End of Range set by the Board	6.83%	6.86%	7.01%

The Board approved the Company's rate of return on average rate base of 7.01% in a range of 6.83% to 7.19% for 2019 in Order No. P.U. 2 (2019). As noted above, the Company's actual return on average rate base for 2019 was 6.97% which was inside the range set by the Board.

The actual rate of return for 2018 was within the range set by the Board.

The actual rate of return for 2017 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. 2 (2019) the Board reconfirmed its previous position as per Order No. P.U. 18 (2016) 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 2019 as reported in Return 24 is as follows:

	2019 Average		2018	2017
	(000's)	Percent	Percent	Percent
Debt	$ 616,343	54.28%	54.53%	54.22%
Preferred equity	8,880	0.78%	0.80%	0.82%
Common equity	510,388	44.94%	44.67%	44.96%
	$ 1,135,611	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 2019 test year in Return 26. The embedded cost of debt for 2019 was 6.00% which represents a 7 bps decrease from the 2018 embedded cost of debt of 6.07%.

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. 2 (2019).

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, 2019 is included on Return 27 of the annual report to the Board. The average common equity for 2019 was $510,388,000 (2018 - $495,374,000). The Company's actual return on average common equity for 2019 was 8.79% (2018 – 8.76%).

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), Order No. P.U. 18 (2016), and Order No. P.U. 2 (2019); and
- recalculated the rate of return on common equity for 2019 and ensured it was in accordance with established practice, Order No. P.U. 32 (2007) and Order No. P.U. 2 (2019).

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, the Company must file a report with its annual return explaining the facts and circumstances contributing to the difference. In 2019 the cost of common equity was 8.50% as per Order No. P.U. 2 (2019). The actual return on average common equity for 2019 was 8.79% 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)	**2019**	**2018**	**2017**
Net Income	**$42,891**	$41,744	$41,526
Income Taxes	**11,299**	12,280	12,882
Interest on long term debt	**35,375**	35,788	35,013
Interest during construction	**(1,933)**	(951)	(1,025)
Other interest and amortization of discount costs	**1,590**	931	893
Total	**$89,222**	$89,792	$89,289
Interest on long term debt	**$35,375**	$35,788	$35,013
Other interest and amortization of discount costs	**1,590**	931	893
Total	**$36,965**	$36,719	$35,906
Interest Coverage (times)	**2.4**	2.4	2.5

The above table shows that the interest coverage had not changed from 2018 to 2019.

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 2019 is 2.4 times.

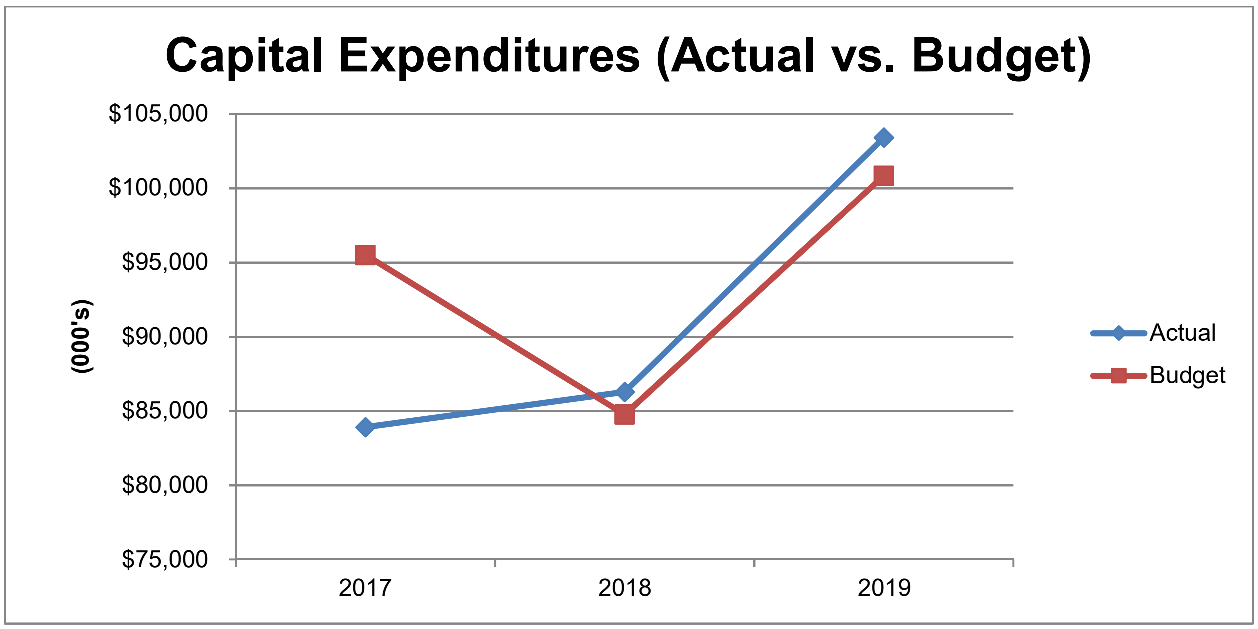
Capital Expenditures

Scope: ***Review the Company's 2019 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 2017 to 2019:

($000's)	**2017**	**2018**	**2019**	**Notes**
Actual	$ 83,921	$ 86,285	$ 103,417	**1**
Budget	$ 95,521	$ 84,776	$ 100,856	
Over (under) budget	(12.14%)	1.78%	2.54%	

Note 1: Total expenditures per the 2019 Capital Budget report includes the carryover amount of $2,879,000 for a total of $106,296,000. The carryover amount is made up of five projects included in the following categories; $150,000 to generation; $310,000 to transmission; $530,000 to renovations; $1,575,000 to transportation; and $314,000 to information systems. According to the Company, these expenditures will occur in 2020.



The following table provides a summary of the capital expenditure activity in 2019 as reported in the Company's *"2019 Capital Expenditure Report"*:

($000's)	Capital Budget			Actual Expenditures		
	Prior Years	2019	Total	Prior Years	2019	Total
2019 Capital Projects (1)	$ -	$ 100,856	$100,856	$ -	$103,417	$103,417
2018 Projects Carried to 2019 & Multi Year Projects:						
Facility Rehabilitation (2)	2,119	-	2,119	2,348	253	2,601
Purchase Mobile Generation	6,000	-	6,000	4,453	1,595	6,048
Rebuild Transmission Lines	5,068	-	5,068	5,027	-	5,027
Duffy Place Roof Replacement (3)	900	-	900	402	699	1,101
System Upgrades	245	-	245	201	-	201
Outage Management System Replacement	2,360	-	2,360	1,758	602	2,360
Human Resource Management System Replacement	422	-	422	481	-	481
	17,114	-	17,114	14,670	3,149	17,819
Grand Total	**$ 17,114**	**$ 100,856**	**$ 117,970**	**$ 14,670**	**$106,566**	**$121,236**

(1) Approved by Order P.U. 35 (2018), P.U. 5 (2019), P.U. 6 (2019) and P.U. 36 (2019).

(2) The Company has noted that the unfavorable budget variance arose from the Second Storage Pond Dam refurbishment project and the Tors Cove Access Road Bridge Replacement project as additional fill material and larger concrete abutments were required due to poor foundation conditions found during excavation. Additional costs were also incurred on the Rocky Pond Turbine Bearing Replacement project due to alignment issues encountered when the generator was reassembled.

(3) The Company has noted that the unfavorable budget variance of the Duffy Place Roof Replacement project arose as a result of deteriorated roof conditions resulting in persistent leaks in 2017 and 2018. Additional expenses were also incurred from this project due to added difficulties experienced when replacing the roof under winter conditions.

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

($000's)	2019 Budget (1)	2019 Actuals (2)	Variance	Carryover (3)	Variance Including Carryover	%
Generation - Hydro	$ 4,782	$ 5,211	$ 429	$ -	$ 429	8.97%
Generation - Thermal	14,242	13,344	(898)	150	(748)	(5.25%)
Substation	19,731	17,133	(2,598)	-	(2,598)	(13.17%)
Transmission	16,559	16,582	23	310	333	2.01%
Distribution	40,151	46,801	6,650	-	6,650	16.56%
General property	3,530	3,420	(110)	530	420	11.90%
Transportation	3,990	2,648	(1,342)	1,575	233	5.84%
Telecommunications	233	312	79	-	79	33.91%
Information systems	10,002	9,582	(420)	314	(106)	(1.06%)
Unforeseen	750	-	(750)	-	(750)	(100.00%)
General expenses capitalized **(4)**	4,000	6,203	2,203	-	2,203	55.08%
Total	**$ 117,970**	**$ 121,236**	**$ 3,266**	**$ 2,879**	**$ 6,145**	**5.21%**

1. Includes prior years projects and current year budgeted amounts as there were projects incomplete at the previous year ends.
2. 2019 actuals include the total expense for projects carried forward from 2018.
3. Represents $2,879,000 of capital projects carried forward to 2020.
4. The increase in General Expenses Capitalized over budget resulted from a change in the capitalization of pension expense associated with Accounting Standards Update 2017-07. This change was approved in Order No. P.U. 2 (2019) and was not included in the original budget for this project according to the company.

As indicated in the table, actual capital expenditures were higher than the approved budget by $3,266,000 (2.77%) and when carryover amounts are taken into account, they were $6,145,000 (5.21%) higher. However, for each category of expenditure, the variances ranged from an over-budget of 55.08% for the General expenses capitalized category to an under-budget of 100.00% 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)
Purchase Mobile Generation	$ 150
Transmission Line 114L Relocation at Customer Request	310
Company Building Renovations	530
Purchase Vehicles and Aerial Devices	1,575
System Upgrades	95
Cybersecurity Upgrades	146
Human Resource Management System Replacement	73
Total Carryover	**$ 2,879**

The Company has provided detailed explanations on budget to actual variances in its "2019 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 2019 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%; and

- 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 1.78% in 2018 and 2.54% in 2019 resulting in no additional reporting requirements.

The allowance for unforeseen items account was not utilized in 2019.

<u>Capital Expenditure Reports</u>

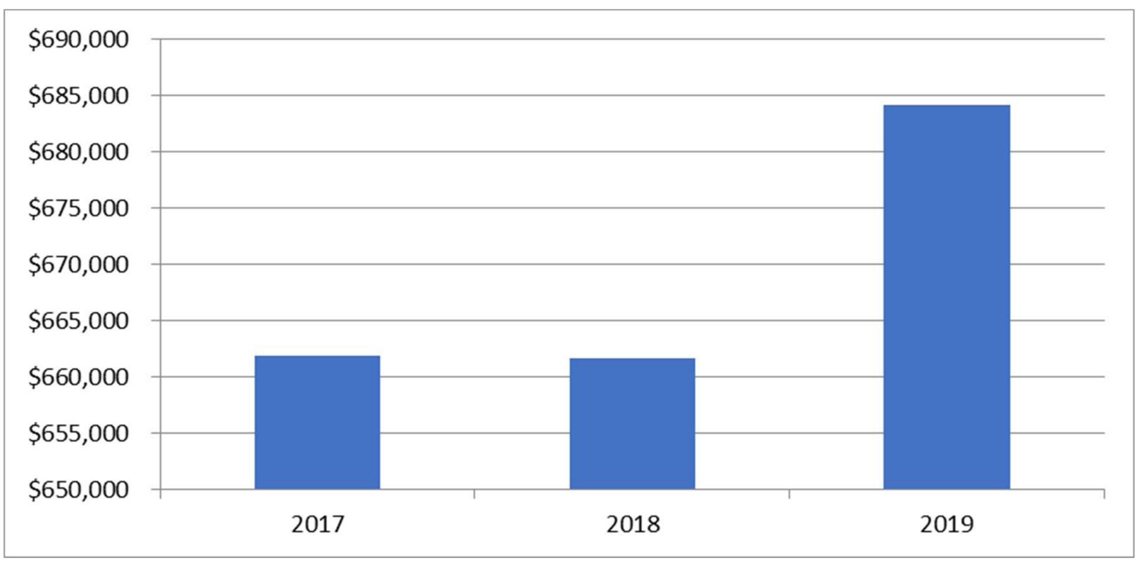
Confirmation was received from the Board that the Company filed quarterly Capital Expenditure reports for the 2019 calendar year.

Revenue from rates

Scope: ***Review the Company's 2019 revenue from rates in comparison to prior years and follow up on any significant variances.***

We have compared the actual revenues from rates for 2017 to 2019 to assess any significant trends. The results of this analysis of revenue by rate class are as follows:

($000's)	2017	2018	2019
Residential	$ 422,237	$ 419,389	$ 432,272
General Service			
0-100 kW	88,507	90,364	93,038
110-1000 kVA	95,565	97,338	101,397
Over 1000 kVA	37,099	35,725	37,916
Streetlighting	16,149	16,255	16,664
Discounts forfeited	2,327	2,643	2,892
Revenue from rates	$ 661,884	$ 661,714	$ 684,179
Year over year percentage change	0.08%	(0.03%)	3.39%



The above graph demonstrates that the Company has seen a 3.39% increase in revenue from rates in 2019 as compared to 2018. The increase is primarily due to higher wholesale electricity rates effective July 1, 2018. These factors were partially offset by the impact of lower electricity sales.

The comparison by rate class of 2019 actual revenues to 2019 budget is as follows:

($000's)	2018	2019	2019 Plan	Actual - Plan Variance	%
Residential	$ 419,389	$ 432,272	$ 425,007	$ 7,265	1.71%
General Service					
0-100 kW	90,364	93,038	90,815	2,223	2.45%
110-1000 kVA	97,338	101,397	99,525	1,872	1.88%
Over 1000 kVA	35,725	37,916	37,721	195	0.52%
Streetlighting	16,255	16,664	16,410	254	1.55%
Discounts forfeited	2,643	2,892	2,587	305	11.79%
Total revenue from rates	$ 661,714	$ 684,179	$ 672,065	$ 12,114	1.80%

We have also compared the 2019 budget energy sales in GWh to the actual sold in 2019:

	2018	2019	2019 Plan	Actual - Plan Variance	%
Residential	3,593.0	3,559.8	3,586.6	(26.8)	(0.75%)
General Service					
0-100 kW	805.4	797.6	792.5	5.1	0.64%
110-1000 kVA	1,022.9	1,024.6	1,031.8	(7.2)	(0.70%)
Over 1000 kVA	422.0	432.0	445.3	(13.3)	(3.08%)
Streetlighting	32.8	33.0	32.8	0.2	0.61%
Total	5,876.1	5,847.0	5,889.0	(42.0)	(0.72%)

Actual 2019 revenue from rates was higher than 2019 Plan with an overall increase in actual sales of $12,114,000 (1.80%) from the 2019 Plan due to increased rates as of October 1, 2019. There was a 0.72% decrease in GWh sold in 2019 compared to 2019 Plan primarily due to the lower average consumption by residential and commercial customers as a result of the overall economic climate in the province. The largest variance in revenue can be seen in the Residential, 0 – 100 kW class, and the 110 – 1000 kVA class where revenues increased by $7,265,000 (1.71%), $2,223,000 (2.45%), and $1,872,000 (1.88%), 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.***

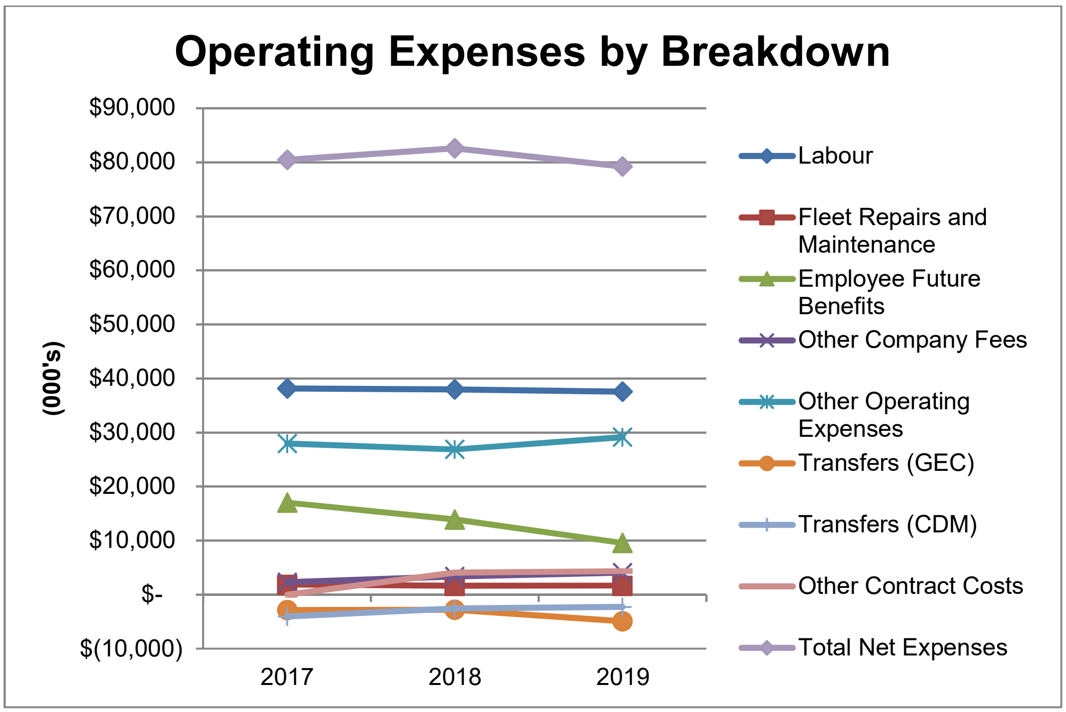
(000's)	Actual 2019	Actual 2018	Actual 2017	Variance 2019-2018
Labour	$ 38,603	$ 39,095	$ 39,341	$ (492)
Reclass OPEB labour cost	(1,041)	(1,125)	(1,173)	84
Total Labour	37,562	37,970	38,168	(408)
Vehicle expense	1,681	1,682	1,854	(1)
Operating materials	1,361	1,511	1,528	(150)
Inter-company charges	2,058	1,847	2,002	211
Plants, Subs, System Oper & Bldgs	3,267	2,812	2,796	455
Travel	1,142	1,127	1,235	15
Tools and clothing allowance	1,289	1,254	1,234	35
Miscellaneous	2,005	1,619	1,879	386
Conservation	2,813	2,732	2,981	81
Taxes and assessments	1,156	1,286	1,252	(130)
Uncollectible bills	1,980	1,490	1,386	490
Insurance	1,397	1,306	1,326	91
Severance & other employee costs	132	68	102	64
Education, training, employee fees	444	403	339	41
Trustee and directors' fees	518	481	489	37
Other company fees	4,058	3,379	2,296	679
Stationary & copying	257	224	214	33
Equipment rental/maintenance	790	784	806	6
Communications	2,803	2,822	2,927	(19)
Advertising	1,581	1,443	1,592	138
Vegetation management	2,042	1,692	2,099	350
Computing equipment & software	1,830	1,628	1,451	202
Total Other	34,604	31,590	31,788	3,014
Pension & early retirement program	3,335	7,726	8,675	(4,391)
OPEB's	6,241	6,194	8,364	47
Total employee future benefits	9,576	13,920	17,039	(4,344)
Total gross expenses	81,742	83,480	86,995	(1,738)
Transfers (GEC)	(4,913)	(2,781)	(2,847)	(2,132)
CDM amortization	4,597	3,706	2,741	891
Other contract expenses	4,353	4,081	-	272
Deferred CDM program costs	(6,864)	(6,239)	(6,758)	(625)
Deferred regulatory costs	294	341	341	(47)
Total net expenses	**$ 79,209**	**$ 82,588**	**$ 80,472**	**$ (3,379)**

The above table provides details of operating and general expenses (including non-regulated expenses) by "breakdown" for 2017, 2018, and 2019.

Overall, net operating expenses decreased by $3,379,000 from 2018 to 2019. 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 2019 are unreasonable.

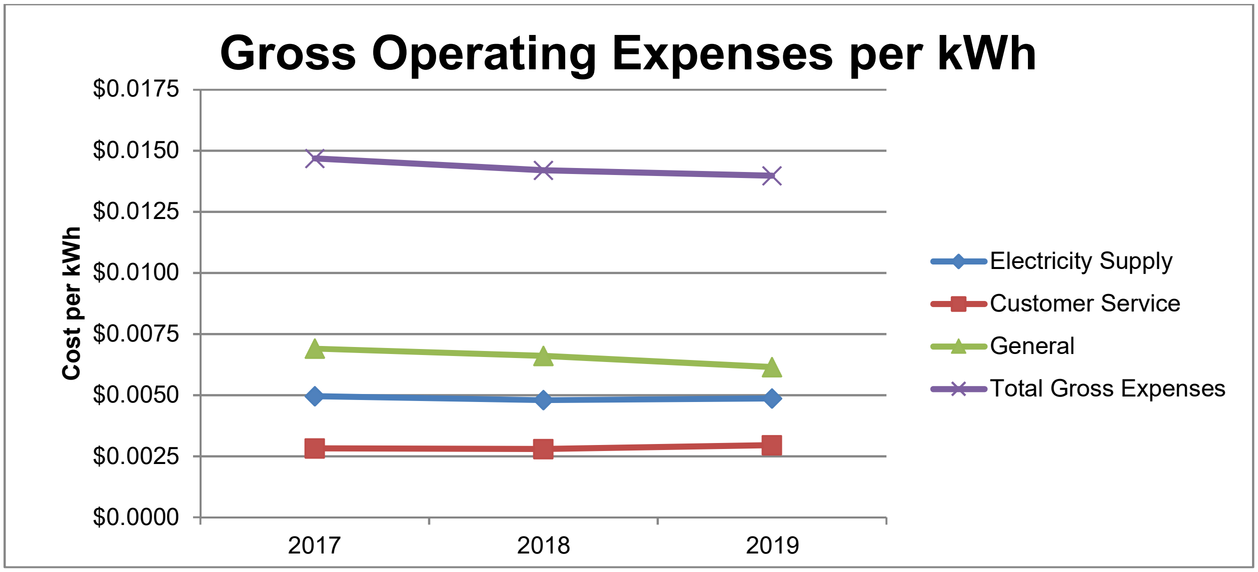
Our detailed review of operating expenses was conducted using the breakdown as documented in the above table. It should also be noted that our review is based upon gross expenses before allocation to GEC and CDM. The following table and graph show the trend in operating expenses by breakdown for the period 2017 to 2019.

	Actual		
(000's)	**2017**	**2018**	**2019**
Labour	$ 38,168	$ 37,970	$ 37,562
Fleet Repairs and Maintenance	1,854	1,682	1,681
Employee Future Benefits	17,039	13,920	9,576
Other Company Fees	2,296	3,379	4,058
Other Operating Expenses	27,979	26,870	29,159
Transfers (GEC)	(2,847)	(2,781)	(4,913)
Transfers (CDM)	(4,017)	(2,533)	(2,267)
Other Contract Costs	-	4,081	4,353
Total Net Expenses	**$ 80,472**	**$ 82,588**	**$ 79,209**



The relationship of operating expenses to the sale of energy (expressed in kWh) from 2017 to 2019 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
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
2019	5,846,600	$28,473	$0.0049	$17,298	$0.0030	$35,971	$0.0062	$81,742	$0.0140



The table and graph show that total gross expenses per kWh have decreased by approximately 1.4% compared to 2018.

There was a decrease in General Costs of $2.9 million, with increases in Customer Service Costs of $0.9 million and in Electricity Supply Costs of $0.3 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 2017 to 2019 (including 2019 plan) is as follows:

	Actual 2019	**Plan 2019**	Actual 2018	Actual 2017	**Actual - Plan**	**Actual 2019-2018**
Executive Group	**6.2**	**6.0**	5.7	6.3	0.2	0.5
Corporate Office	**20.8**	**20.0**	19.8	20.0	0.8	1.0
Finance and IT	**93.5**	**91.6**	91.6	88.9	1.9	1.9
Engineering and Operations	**383.2**	**385.2**	372.9	365.4	(2.0)	10.3
Customer Relations	**72.8**	**69.1**	78.8	84.3	3.7	(6.0)
	576.5	**571.9**	568.8	564.9	4.6	7.7
Temporary employees	**39.7**	**52.3**	50.4	46.3	(12.6)	(10.7)
Total	**616.2**	**624.2**	619.2	611.2	(8.0)	(3.0)

The overall number of FTE's in 2019 compared to 2018 decreased by 3. The budgeted number of FTEs in the 2019 Plan was 624.2 versus actual of 616.2. The variances between 2019, 2019 Plan and 2018 are the result of the following:

- Finance and Information Technology is higher than plan due to a shift from temporary employees and timing of planned hires. Additionally, the increase from 2018 is due to increased labour for the Customer Information System ("CIS") Assessment project;
- Engineering and operations is consistent with plan. However, the increase over 2018 is due to a shift in metering positions from Customer Relations and increased labour for capital distribution work;
- Customer relations is higher than plan due to a shift from temporary employees. The decrease from 2018 is primarily due to lower labour for metering services and meter reading, a reallocation of metering positions to Engineering & Operations, and timing of planned hours; and
- Temporary Employees is lower than plan and 2018 primarily due to a shift from temporary to regular employees and timing of planned hours.

An analysis of salaries and wages by type of labour and by function from 2017 to 2019 is as follows:

(000's)	**Actual 2019**	Actual 2018	Actual 2017	**Variance 2019-2018**
Type				
Internal labour	**$ 66,023**	$ 65,090	$ 64,399	$ 933
Overtime	**6,568**	6,568	6,807	-
	72,591	71,658	71,206	933
Contractors	**17,523**	15,409	12,883	2,114
	$ 90,114	$ 87,067	$ 84,089	$ 3,047
Function				
Operating	**$ 38,603**	$ 39,095	$ 39,341	$ (492)
Capital and miscellaneous	**51,511**	47,972	44,748	3,539
Total	**$ 90,114**	$ 87,067	$ 84,089	$ 3,047
Year over year percentage change	**3.50%**	3.54%	6.27%	

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 2019 were $3,047,000 (3.50%) higher than 2018.

Internal labour costs in 2019 were higher than 2018 due to normal labour inflation and increased labour for capital distribution work, increased labour for the CIS Assessment project and the Human Resource Management System. This increase was largely offset by lower corporate costs and reduced labour for metering services, meter reading and timing of planned hires.

Contract labour for 2019 was higher than 2018 due to increased labour for transmission rebuilds and third party work for telecommunication companies.

Capital and miscellaneous labour for 2019 was higher than 2018 due to increased labour for capital distribution work, transmission rebuilds, third party work for telecommunication companies, and inflationary increases.

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 2017 to 2019 are included in the table below:

Salary Cost Per FTE

	Actual 2019	Actual 2018	Actual 2017	**Variance 2019-2018**
Total reported internal labour costs	**$ 66,023**	$ 65,090	$ 64,399	$ 933
Benefit costs (net)	**(8,926)**	(8,939)	(8,960)	13
Other adjustments	**(1,126)**	(725)	(1,171)	(401)
Base salary costs	**55,971**	55,426	54,268	545
Less: executive compensation	**(1,938)**	(1,693)	(2,016)	(245)
Base salary costs (excluding executive)	**$ 54,033**	$ 53,733	$ 52,252	$ 300
FTE's (including executive members)	**616.2**	619.2	611.2	
FTE's (excluding executive members)	**612.2**	615.5	606.9	
Average salary per FTE	**90,833**	89,512	88,789	
% increase	**1.48%**	0.81%	3.62%	
Average salary per FTE (excluding executive members)	**88,261**	87,300	86,097	
% increase	**1.10%**	1.40%	3.39%	

The above analysis indicates that the rate of increase in average salary per FTE excluding executive members for 2019 has decreased from 2018, and 2018 decreased from 2017.

Newfoundland Power has two collective agreements governing its union employees represented by the International Brotherhood of Electrical Workers, Local 1620 (the “IBEW”). Negotiated wage increases in the collective agreements included a 2.5% increase on January 1st, 2017. In addition, new collective agreements for both were signed on May 6, 2019, and included the wage increases outlined below over the term of the contracts.

	Oct. 1, 2017	Jan. 1, 2019	Jan. 1, 2020	Jan. 1, 2021	Jan. 1, 2022
Craft	1.0%	1.50%	2.00%	2.00%	2.25%
Clerical	1.0%	1.50%	2.00%	2.00%	2.25%

These negotiated wage increases were applied retroactively to October 1, 2017, i.e. 2.5% January 1, 2017 and 1% October 1, 2017. Timing of the wage increases and retroactive amounts are the primary reason for the lower level of percentage increase from 2017 to 2019 for the average salary per FTE (excluding executive members).

Short Term Incentive (STI) Program

The following table outlines the actual results for 2017 to 2019 and the targets set for 2019:

Measure	Target 2019	Actual 2019	Actual 2018	Actual 2017
Controllable Operating Costs/Customer	**$ 232.70**	$ 231.00	$ 225.10	$ 228.80
Earnings	**$ 40.9M**	$ 42.3M	$ 41.2M	$ 41.0M
Cash Flow from Operating Activities	**$ 108.9M**	$ 111.2M	$ -	$ -
Reliability - Duration of Outages (SAIDI)	**2.39**	2.34	2.65	2.28
Customer Satisfaction - % Satisfied	**85.6%**	85.8%	85.6%	86.5%
Injury Frequency Rate	**0.92**	0.37	-	0.18
Regulatory Performance	**-**	-	150%	120%

2019 STI results were adjusted to remove the impact of the severe weather conditions in February, September and November. In 2019 the ‘regulatory performance’ measure was replaced by the ‘cash flow from operating activities’ measure.

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 2019 is established as a percentage of base pay for the three employee groups. For 2019, all six measures above were met.

The following table illustrates the target as a percentage of base pay, together with the actual STI payouts for 2017 to 2019:

	Target 2019	Actual 2019	Target 2018	Actual 2018	Target 2017	Actual 2017
President	50%	70.00%	50%	60.30%	50%	66.32%
Executive	35% - 40%	50.42%	35% - 40%	47.04%	40%	57.28%
Directors	15%	17.94%	15%	18.28%	15%	20.03%

STI actual payout rates for ‘President’, ‘Executive’ and ‘Director’ employee groups are higher than the prior year and each payout rate exceeded targets consistent with 2018 and 2017.

In dollar terms, the STI payouts for 2017 to 2019 are as follows:

	Actual 2019	Actual 2018	Actual 2017	Variance 2019-2018
President	**$ 287,000**	$ 230,000	$ 240,396	$ 57,000
Executive	**416,000**	346,000	506,604	70,000
Directors	**311,000**	296,200	332,999	14,800
Total	**$ 1,014,000**	$ 872,200	$ 1,079,999	$ 141,800
Year over Year % change	**16.26%**	-19.24%	7.22%	

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 2019, the non-regulated portion (before tax adjustment) was $344,832 (2018 - $262,753).

Executive Compensation

The following table provides a summary and comparison of executive compensation for 2017 to 2019:

	Base Salary	Short Term Incentive	Other	Total
2019				
Total executive group	$ 1,235,000	$ 703,000	$ 421,412	$ 2,359,412
Average per executive (4)	**$ 308,750**	**$ 175,750**	**$ 105,353**	**$ 589,853**
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**
% Average change 2019 vs 2018	10.60%	22.05%	(33.14%)	1.57%
Per executive % average change 2019 vs 2018	3.41%	14.12%	(37.50%)	(5.03%)

Base salary for the executive group in 2019 increased from 2018 primarily due to the increase in FTE for executives which in 2019 was 4 FTE compared 3.74 FTE in 2018. In 2019, four executives held positions for the entire year resulting in 4 FTE. This increase compared to 2018 is due to the fact that in 2018 there were changes in executive positions, including the appointment of a new CEO effective June 1, 2018 and the new executive position of Vice President, Energy Supply and Planning effective September 1, 2018.

Other compensation for the executive group in 2019 decreased from 2018, primarily due to a vacation payout for an executive in 2018. STI payouts and performance share unit payouts were agreed to the Board of Directors' minutes.

Company Pension Plan

For 2019, we reviewed the accounts supporting the gross charge of $3,335,000 of pension expense for the Company. A detailed comparison of the components of pension expense for 2017 to 2019 is below:

	Actual 2019	Actual 2018	Actual 2017	Variance 2019-2018
Pension expense per actuary	**$ 639,000**	$ 5,163,000	$ 6,165,000	$ (4,524,000)
Pension uniformity plan (PUP)/supplemental employee retirement program (SERP)	**347,000**	501,000	571,000	(154,000)
Group RRSP @ 2%[1]	**315,000**	289,000	321,000	26,000
Individual RRSP's	**2,055,000**	1,790,000	1,640,000	265,000
Less: Refunds (net of other expenses)	**(21,000)**	(17,000)	(22,000)	(4,000)
Total	**$ 3,335,000**	$ 7,726,000	$ 8,675,000	$ (4,391,000)
Year over year percentage change	**(56.83%)**	(10.94%)	(11.14%)	

Note 1: Plan amendment which increased the contribution rate from 1.5% to 2.0% as of May 2019.

Overall, pension expense for 2019 is lower than 2018 primarily due to lower current service costs and lower amortization of net actuarial losses as a result of an increase in the discount rate.

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 30.74% in 2019.

The employer's portion of the contributions to the Group RRSP is calculated as 2.0% (increased to 2% as of May 2019) of the base salary paid to the plan participants. Individual RRSP contributions increased as a result of a plan amendment which increased the contribution rate for the 5.75% plan to 6.25% as of May 2019. New hires are added to the Individual RRSP Plan whereas the majority of retirements are out of the Group RRSP Plan. The increase in Group RRSP contributions made by the employer was primarily the result of a plan amendment which increased the contribution rate from 1.5% to 2.0% as of May 2019, which was partially offset by retirements.

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 2017 to 2019 are as follows:

(000's)	Actual 2019	Actual 2018	Actual 2017	Variance 2019-2018
Accrued OPEBs	**$ 3,657**	$ 3,648	$ 5,861	$ 9
Amortization of transitional balance	**3,504**	3,504	3,504	-
Amount capitalized	**(920)**	(958)	(1,001)	38
Total	**$ 6,241**	$ 6,194	$ 8,364	$ 47

According to the Company, the decrease in OPEBs expense after 2017 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 2018 to 2019 and investigated any unusual fluctuations;
- reviewed detailed listings of charges for 2019 and investigated any unusual items;
- vouched a sample of transactions for 2019 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 2017 to 2019 for charges to and from Newfoundland Power Inc.:

	Actual 2019	Actual 2018	Actual 2017	Variance 2019-2018
Charges from related companies				
Regulated	**$ 339,937**	$ 1,121,634	$ 225,084	$ (781,697)
Non-Regulated	**2,360,484**	2,101,634	2,143,224	258,850
Total	**$ 2,700,421**	$ 3,223,268	$ 2,368,308	$ (522,847)
Charges to related companies	**$ 1,214,048**	$ 643,394	$ 2,206,966	$ 570,654

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 2019.

- Fortis Inc. estimated its net pool of operating expenses for 2019 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 2019, a "true-up" calculation was completed to reflect actual recoverable expenses which were determined to be $2,058,000 and are summarized as follows:

2019 Recoverable Expenses from Fortis Inc.

	Amount	
Staffing and Staffing Related	$1,332,000	Non-regulated
Director Fees and Travel	178,000	Non-regulated
Consulting and Legal fees	129,000	Non-regulated
Trustee Agent Fees	27,000	Regulated
Audit and Other Fees	44,000	Non-regulated
2018 Recovery True Up	(8,000)	Non-regulated
2019 True Up	(38,000)	Non-regulated
Annual Meeting Expenses	43,000	Non-regulated
Insurance (D&O)	44,000	Non-regulated
Other Costs	307,000	Non-regulated
	2,058,000	
Less amounts previously billed:		
Q1 2019	708,000	
Q2 2019	555,000	
Q3 2019	440,000	
Q4 2019 balance owing	$ 355,000	

As detailed above, trustee agent fees for $27,000 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. There were additional invoices of $579,133 received directly from Fortis during 2019 for total Fortis charges of $2,637,133 (2,058,000+579,133), of which $276,649 were regulated and $2,360,484 were non-regulated. 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 2017 to 2019 with Fortis Inc.:

(Regulated)	Actual 2019	Actual 2018	Actual 2017	Variance 2019-2018
Charges from Fortis Inc.				
Trustee fees and share plan costs	**$ 27,000**	$ 25,000	$ 26,000	$ 2,000
Miscellaneous	**208,765**	941,488	133,361	(732,723)
Staff Charges	**40,884**	92,711	-	(51,827)
	$ 276,649	$ 1,059,199	$ 159,361	$ (782,550)
Year over year percentage change	**(73.88%)**	564.65%	85.18%	
Charges to Fortis Inc.				
Postage and couriers	**$ 2,181**	$ 3,165	$ 4,113	$ (984)
Staff charges	**51,573**	27,471	43,581	24,102
IS Charges	**-**	-	5,888	-
Pole removal and installation	**-**	-	93	-
Miscellaneous	**31,561**	97,880	49,406	(66,319)
	$ 85,315	$ 128,516	$ 103,081	$ (43,201)
Year over year percentage change	**(33.62%)**	24.67%	62.47%	

The most significant fluctuations from our analysis of regulated charges from Fortis Inc. is a decrease in the miscellaneous account of $732,723 and a decrease in staff charges of $51,827. 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 2017 to 2019:

(Non-Regulated)	Actual 2019	Actual 2018	Actual 2017	Variance 2019-2018
Charges from Fortis Inc.				
Director's fees and travel	**$ 178,000**	$ 139,000	$ 202,000	$ 39,000
Staff charges	**1,294,000**	1,054,000	1,204,000	240,000
Miscellaneous	**888,484**	908,634	732,811	(20,150)
	$ 2,360,484	$ 2,101,634	$ 2,138,811	$ 258,850
Charges from Maritime Electric				
Miscellaneous	**$ -**	$ -	$ 4,413	$ -
	$ 2,360,484	$ 2,101,634	$ 2,143,224	$ 258,850

Director's fees and travel increased by $39,000 primarily due to the Director's Share Unit expense. Otherwise, director's fees and travel stayed relatively consistent. There are a variety of factors that influence the Director's Share Unit expense, such as the number of active directors and the units outstanding. However, the main factors causing the increase include an increase in dividend rates from 2018 to 2019 resulting in more units outstanding, and more share price growth assumed in 2019 than in 2018.

Staff charges have increased from 2018 by $240,000 primarily due to the change in share based compensation. In addition to higher units outstanding for share based plans, 2019 saw a large increase in the share price relative to 2018 which leads to higher overall expense recognition.

Miscellaneous charges decreased by $20,150 due to a variety of factors. According to the Company, the most significant trend this year is that while spending levels increased for 2019, more spending was determined to be non-recoverable from subsidiaries, resulting in lower billing to Newfoundland Power for 2019 compared to 2018. Non-recoverable amounts are amounts incurred at Fortis Inc. that do not benefit the subsidiaries such as business development projects and donations. During 2019, a higher portion of costs were related to these types of projects, resulting in the lower allocation to subsidiaries.

The following table provides a summary and comparison of the other intercompany transactions for 2017 to 2019:

Intercompany Transactions (Other)	**Actual 2019**	**Actual 2018**	**Actual 2017**	**Variances 2019-2018**
Charges to Fortis Ontario Inc.				
Staff charges	**$ 390,837**	$ 371,640	$ 138,200	$ 19,197
Miscellaneous	**326,592**	35,193	1,703	291,399
	$ 717,429	$ 406,833	$ 139,903	$ 310,596
Charges from Fortis Ontario Inc.				
Miscellaneous	**$ 4,875**	$ -	$ -	$ 4,875
Charges to Maritime Electric				
Staff charges	**$ 276,106**	$ -	$ 3,719	$ 276,106
Miscellaneous	**78,496**	550	550	77,946
	$ 354,602	$ 550	$ 4,269	$ 354,052
Charges from Maritime Electric				
Miscellaneous	**$ 6,193**	$ 15,258	$ 16,713	$ (9,065)
Charges to Central Hudson Gas & Electric				
Staff charges	**$ 6,321**	$ -	$ -	$ 6,321
Charges from Central Hudson Gas & Electric				
Miscellaneous	**$ 10,190**	$ 5,705	$ 8,034	$ 4,485

Intercompany Transactions (Other) Cont'd.	Actual 2019	Actual 2018	Actual 2017	Variances 2019-2018
Charges to Belize Electric Company Ltd.				
Staff charges	**$ 35,226**	$ 91,553	$ 112,387	$ (56,327)
Miscellaneous	**475**	-	845	475
	$ 35,701	$ 91,553	$ 113,232	$ (55,852)
Charges to FortisAlberta Inc.				
Miscellaneous	**$ 5,000**	$ 4,980	$ 4,740	$ 20
Charges from FortisAlberta Inc.				
Miscellaneous	**$ 37,612**	$ 38,073	$ 37,611	$ (461)
Charges to FortisBC Inc./ FortisBC Holdings				
Staff Charges	**$ -**	$ -	$ 11,578	$ -
Miscellaneous	**9,680**	9,370	9,310	310
	$ 9,680	$ 9,370	$ 20,888	$ 310
Charges from FortisBC Inc./ Fortis BC Holdings				
Miscellaneous	**$ 4,418**	$ 3,399	$ 3,365	$ 1,019
Charges to Caribbean Utilities Co. Limited				
Staff charges	**$ -**	$ -	$ 4,240	$ -
Charges to Fortis Turks and Caicos				
Staff charges	**$ -**	$ -	$ 698,896	$ -
Miscellaneous	**-**	1,592	1,117,717	(1,592)
	$ -	$ 1,592	$1,816,613	$ (1,592)

The most significant fluctuations from our analysis of other intercompany charges for 2019 compared to 2018 are as follows:

- Staff charges to Belize Electric Company Ltd. decreased by $56,327 primarily due to decreases in technical support requirements compared to 2018;
- Miscellaneous charges to Fortis Ontario Inc. increased by $291,399 primarily due to an employee's 2018 short term incentive payments amounting to $156,200 and another charge to refund the company for $163,200 for the same employee ($319,400); and
- Staff charges and miscellaneous charges to Maritime Electric have increased by $276,106 and $77,946 respectively as the 2019 year included charges relating to Hurricane Dorian.

The Company entered into the following short-term loan agreements with related parties during the year:

Lender	Maximum Amount Borrowed	Date Borrowed	Date Repaid	Interest Rate	Total Interest Cost [1]
Fortis Inc.	$ 75,000,000	June 20, 2019	August 29, 2019	2.39625%	$ 253,244
Fortis Inc.	20,000,000	August 20, 2019	August 29, 2019	2.39125%	11,792
Fortis Inc.	60,000,000	December 20, 2019	On Demand[2]	2.47875%[3]	44,821
	$ 155,000,000				$ 309,857

1. Interest charged by Fortis is based on its credit facility, less a discount of 36bps.
2. On December 31, 2019, Newfoundland Power re-paid $9,500,000 plus $44,821 interest.
3. Interest rate was reset on January 20, 2020.

The interest rates charged on each of the loans above were lower than what would have been charged under the Company's debt facilities. Fortis Inc. provides Newfoundland Power with an interest discount of 36bps which is equal to the standby fee of 16bps and a direct Fortis discount of 20bps.

In Order No. P.U. 19 (2003), the Board provided instructions to the Company with respect to the recording and reporting of intercompany transactions. Some of these instructions required reports to be filed with the Board at various times in 2019. Confirmation was received from the Board that quarterly reports relating to intercompany transactions have been filed for 2019.

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 2019 and vouching of a sample of individual transactions to supporting documentation.

(000's)	Actual 2019	Actual 2018	Actual 2017	Variance 2019-2018
Other company fees				
Other company fees	**$ 3,746**	$ 2,855	$ 3,082	$ 891
Regulatory hearing costs	**312**	524	(786)	(212)
	$ 4,058	$ 3,379	$ 2,296	$ 679
Year over year percentage change	**20.1%**	47.2%	(22.0%)	
Deferred regulatory costs				
Total deferred regulatory costs	**$ 294**	$ 341	$ 341	$ (47)
Year over year percentage change	**(13.8%)**	0.0%	98.3%	

Other Company Fee costs for 2019 were higher than 2018. According to the Company, this is primarily due to higher consultant costs for customer energy conservation programs, CIS Assessment project and dam safety reviews partially offset by lower consultant costs for regulatory activity. 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 2017 to 2019 is as follows:

(000's)	Actual 2019	Actual 2018	Actual 2017	Variance 2019-2018
Miscellaneous	**$ 1,231**	$ 994	$ 1,117	$ 237
Cafeteria and lunchroom Supplies	**75**	77	84	(2)
Promotional items	**169**	137	199	32
Computer Software	**3**	10	2	(7)
Damage claims	**278**	174	216	104
Community relations activities	**1**	2	3	(1)
Donations and charitable advertising	**195**	183	217	12
Books, magazines and subscriptions	**18**	7	7	11
Miscellaneous lease payments	**35**	35	34	-
Total miscellaneous expenses	**$ 2,005**	$ 1,619	$ 1,879	$ 386
Year over year percentage change	**23.84%**	(13.84%)	3.19%	

Miscellaneous expenses by their very nature can fluctuate from year to year. From 2018 to 2019 these expenses have increased by 23.84% overall. According to the Company, miscellaneous costs for 2019 were higher than 2018 due to increased damage claims, adjustments to materials and supplies, and customer energy conservation education and outreach costs.

Our procedures in this expense category for 2019 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 2019 expenses are unreasonable.

Conservation and Demand Management (CDM)

In compliance with Order No. P.U. 7 (1996-97), the Company filed the 2019 Conservation and Demand Management Report with the Board. This report provided a summary of 2019 CDM activities and costs as well as the outlook for 2020.

In 2015, Newfoundland and Labrador Hydro and Newfoundland Power ("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 2019, the Utilities continued to implement the 2016 Plan. These activities include: the development of new educational resources for business; extending the take CHARGE Insulation and Thermostat Rebate Programs to oil heat customers in partnership with the government of Newfoundland and Labrador and the Government of Canada; continuing delivery of the Instant Rebates program; and launching a heat pump load research study.

CDM costs in 2019 totaled $7,772,000 compared to $7,252,000 in 2018, a $520,000 increase. Conservation costs are higher than in 2018 due to increased costs associated with head pump load research.

In 2019, $6,864,000 ($4,805,000 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.

General Expense Capitalized (GEC)

($000's)	Actual 2019	Actual 2018	Actual 2017	Variance 2019-2018
Transfers (GEC)	**(4,913)**	(2,781)	(2,847)	(2,132)

The capitalization of pension costs has been reflected through the Company's General Expenses Capitalized ("GEC") account based on the GEC methodology approved by the Board in Order No. P.U. 3 (1995-96). In that Order, it was noted that Newfoundland Power was the only utility that included pension costs in a GEC allocation. In the Company's report to the Board, dated August 14, 2020, titled "Review of Capitalization Policies and Guidelines" it was noted by the Company that its practice of capitalizing pension in GEC or capitalized overhead is not common among Canadian utilities. It was also noted in the report that ten of the eleven respondents to a survey capitalize pension costs by means of a labour loader.

In Order No. P.U. 2 (2019) the Board approved the Company's proposal to increase the allocation of pension costs to GEC from 11% to 46%, to comply with Accounting Standards Update 2017-07 – *Improving the Presentation of Net Periodic Pension Costs and Net Periodic Post-Retirement Benefit Cost*, issued in March 2017 by the Financial Accounting Standards Board (the "Update"). This Update provided guidance that the amount of current service pension cost capitalized should reflect the proportion of labour costs that are related to capital work. Utilities that capitalize pension costs using a labour loader would already follow the proportion of labour costs that are related to capital work and therefore would not have been impacted by this Update.

Transfers to GEC for 2019 were higher than 2018 due to the increase in the capitalization percentage of current service pension costs as noted above.

Other Operating 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 2019 and 2018.

($000's)	Actual 2019	Actual 2018	Actual 2017	Variance 2019-2018
Vehicle expense	**1,681**	1,682	1,854	(1)
Operating materials	**1,361**	1,511	1,528	(150)
Inter-company charges	**2,058**	1,847	2,002	211
Plants, Subs, System Oper & Bldgs	**3,267**	2,812	2,796	455
Travel	**1,142**	1,127	1,235	15
Tools and clothing allowance	**1,289**	1,254	1,234	35
Conservation	**2,813**	2,732	2,981	81
Taxes and assessments	**1,156**	1,286	1,252	(130)
Uncollectible bills	**1,980**	1,490	1,386	490
Insurance	**1,397**	1,306	1,326	91
Severance & other employee costs	**132**	68	102	64
Education, training, employee fees	**444**	403	339	41
Trustee and directors' fees	**518**	481	489	37
Stationary & copying	**257**	224	214	33
Equipment rental/maintenance	**790**	784	806	6
Communications	**2,803**	2,822	2,927	(19)
Advertising	**1,581**	1,443	1,592	138
Vegetation management	**2,042**	1,692	2,099	350
Computing equipment & software	**1,830**	1,628	1,451	202
CDM amortization	**4,597**	3,706	2,741	891

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

1. Inter-company charges were higher in 2019 than in 2018 due to higher recoveries charged by Fortis;
2. Plants, Subs, System Oper And Bldgs costs for 2019 were higher than 2018 due to increased building repair and maintenance costs and higher generation taxes;
3. Uncollectible bills for 2019 were higher than 2018 reflecting a decline in general economic conditions;
4. Vegetation management costs for 2019 were higher than 2018 due to increased vegetation management activity for distribution;
5. Amortization of Deferred CDM costs commenced in 2014 and is higher in 2019 due to the inclusion of the sixth year of deferred customer energy conservation programming costs.

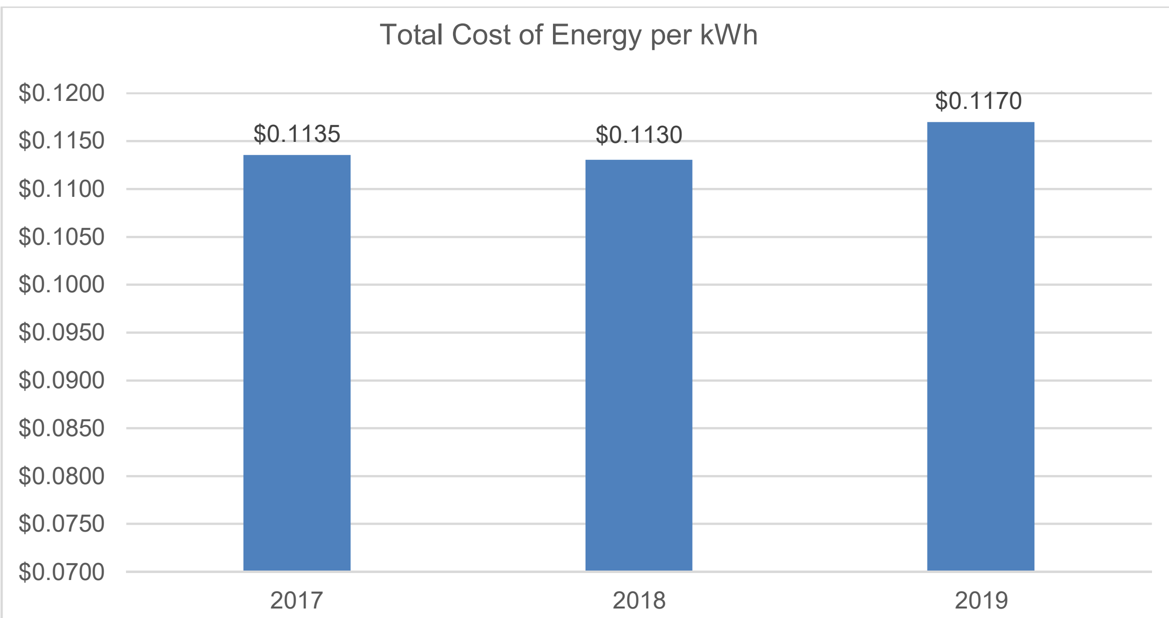
Other Costs

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 2017 to 2019:

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
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
2019	5,846,600	$ 79,209	$ 444,861	$ 1,752	$ 68,019	$ 35,931	$ 11,299	$ 42,891	$683,962	$ 0.1170



Purchased Power

We have reviewed the Company's purchased power expense for 2019 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 increased by $17.6 million, from $427.2 million in 2018 to $444.9 million in 2019. According to the Company, the costs were higher in 2019 primarily due to an increase in wholesale electricity rates effective July 1, 2018. We also noted that the company experienced an increase in wholesale electricity rates effective October 1, 2019 as approved in Order No. P.U. 30 (2019).

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 2019 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 2019; and
- assessed the overall reasonableness of the depreciation for 2019.

Amortization expense for 2019 is $68,019,000 as compared to $65,170,000 for 2018, representing a 4.4% increase. The 2019 and 2018 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)	2019	2018	Variance 2019-2018	%
Depreciation and amortization as reported	**$ 68,019**	$ 65,170	$ 2,849	4.4%
Less: Tax on Cost of Removal (1)	**(5,953)**	(5,704)	(249)	4.4%
Depreciation of Fixed Assets	**$ 62,066**	$ 59,466	$ 2,600	4.4%

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 2019, 2018 and 2017:

(000's)	2019	2018	2017	Variance 2019-2018	Variance 2018-2017
Depreciation of Fixed Assets	**$ 62,066**	$ 59,466	$ 57,487	$ 2,600	$ 1,979

Depreciation of fixed assets for 2019 is $62,066,000 as compared to $59,466,000 for 2018, representing a 4.4% increase. The change is attributable to an increase of depreciable assets by approximately $90,430,000.

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), Order No. P.U. 18 (2016), and Order No. P.U. 2 (2019). 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 2019.

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 2017 to 2019:

(000's)	Actual 2019	Actual 2018	Actual 2017	Variance 2019-2018
Interest				
Long-term debt	**$ 35,375**	$ 35,788	$ 35,013	$ (413)
Other	**1,384**	712	672	672
Amortization				
Debt discount	**235**	235	234	-
Interest charged to construction	**(1,063)**	(523)	(554)	(540)
Total Finance charges	**$ 35,931**	$ 36,212	$ 35,365	$ (281)
Year over year percentage change	**(0.78%)**	2.40%	0.37%	

There has been little change in total finance charges as the Company incurred a slight decrease from $36.2 million in 2018 to $35.9 million in 2019. From this analysis and explanations provided by the Company, the following observations were made with respect to the more significant fluctuations:

1. Other interest was higher due to short term borrowings due primarily to the financing of the 2019 Capital program; and
2. Interest charged to construction was higher due to a number of larger capital projects including the build and purchase of a new mobile gas turbine and larger IT projects such as Human Resources Information Systems (HRIS).

Based upon our analysis, nothing has come to our attention to indicate that the finance charges for 2019 are unreasonable.

Income Tax Expense

We have reviewed the Company's income tax expense for 2019 and have noted that the effective income tax rate decreased from 22.7% in 2018 to 20.9% in 2019. 2019 and 2018 results in the following effective rates:

	2019	2018	2017	2019-2018
Income tax expense	**$ 11,299**	$ 12,280	$ 12,882	$ (981)
Earnings before income tax	**$ 54,190**	$ 54,024	$ 54,408	$ 166
Effective income tax rate	**20.9%**	22.7%	23.7%	(1.8%)

Income tax expense decreased by $981,000 compared to 2018. The statutory tax rate was 30.0% for both 2019 and 2018.

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 2019 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 $365,056 for the current period compare to a total of $378,633 for the same period during the previous year. According to the Company, the credit total for the 2018-2019 winter season is lower than the previous season total primarily due to higher number of customer curtailment failures. There were 23 option participants in 2018-2019, compared to 22 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 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 2019 to prior years and investigated any unusual fluctuations;
- reviewed detailed listings of expenses for 2019 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 2019	Actual 2018	Actual 2017	Variance 2019-2018
Charged from Fortis Companies	**$ 2,115,024**	$ 1,904,428	$ 2,121,500	$ 210,596
Performance and restricted share units	**665,058**	346,789	687,500	318,269
Donations and charitable advertising	**336,662**	295,769	301,700	40,893
Executive short term incentive	**419,479**	514,004	361,900	(94,525)
Miscellaneous	**40,265**	61,088	45,000	(20,823)
	3,576,488	3,122,078	3,517,600	454,410
Less: Income Taxes	**1,072,946**	936,623	1,055,300	136,323
Total non-regulated (net of tax)	**$ 2,503,542**	$ 2,185,455	$ 2,462,300	**$ 318,087**

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 2019, this represents an addition to non-regulated expenses (before tax adjustment) of $419,479 (2018 - $514,004). 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 2019 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 2018 and 2019:

(000's)	2019 Actual	2018 Actual	Variance 2019 - 2018
Regulatory Assets			
Rate stabilization account	$ -	$ 1,607	$ (1,607)
OPEBs asset	21,024	24,528	(3,504)
Deferred GRA costs	706	-	706
Conservation and demand management deferral	24,815	22,549	2,266
Demand management incentive	2,687	-	2,687
Employee future benefits	86,366	82,556	3,810
Weather normalization account	8,078	2,168	5,910
Deferred income taxes	220,232	212,900	7,332
	$ 363,908	$ 346,308	$ 17,600
Regulatory Liabilities			
Rate stabilization account	$ 16,107	$ 3,979	$ 12,128
Cost recovery deferral	1,752	-	1,752
Future removal and site restoration provision	168,740	160,047	8,693
	$ 186,599	$ 164,026	$ 22,573

Rate Stabilization Account

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. In 2019, the annual July 1st rate adjustment was postponed, as ordered by the Board, to coincide with customer rate implementation as a result of Hydro's 2017 General Rate Application, which resulted in a October 1, 2019 implementation as approved in Order No. P.U. 31 (2019).

As of December 31, 2019, there was a charge to the RSA of $10,023,800 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. 31 (2019).

Pursuant to Order No. P.U. 31 (2010) the Board approved the Company's proposal to create the 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 31st in the year in which the difference arises. As of March 31, 2019, the credit balance of $62,200 in the OPEBVDA account was transferred to the RSA, as approved in Order No. P.U. 16 (2013).

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, 2019, the balance of $833,658 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, 2019, $2,167,605 and $4,597,148 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 which has a Nil balance in 2018 therefore no impact on RSA in 2019.

Pursuant to Order No. P.U. 2 (2019) the Board approved the Company's proposed disposition of the 2019 Revenue Requirement Shortfall and differences between the actual and estimated 2019 Hearing Costs. As of March 31, 2019, the balance of $145,000 in the Revenue Requirement Shortfall account was credited to the RSA and the balance of $670,272 was debited to the RSA balance for the 2019 Hearing costs.

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 $52.6 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. 2 (2019) the Board approved the deferral of cost related to 2019/2020 GRA as well as amortization of this deferral over a 34 month period commencing on March 1, 2019 and ending December 31, 2021. Actual costs incurred and deferred were approximately $1,000,000 with amortization of $294,000 incurred in 2019.

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, 2019 were $24,815,000 with amortization of $4,597,148 in 2019.

Demand Management Incentive

In Order No. P.U. 32 (2007) the Board approved the Company's proposal to create the Demand Management Incentive Account to replace the Purchased Power Unit Cost Variance Reserve. This account aims to isolate the demand costs and is equal to plus or minus 1% of test year wholesale demand charges. The Demand Management Incentive as at December 31, 2019 was $2,687,000 ($1,881,000 after tax).

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; and
- 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, 2019, the regulated asset for employee future benefits was $86,366,000.

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 31st of the following year. In Order No. P.U. 10 (2020) the Board approved the December 31, 2019 net regulatory asset balance in the Weather Normalization Account of $8,078,000 ($5,654,000 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, 2019 was $220,232,000.

Cost Recovery Deferral

In 2019 there was an over-recovery of revenue due to a March 1, 2019 rate implementation date. In Order No. P.U. 2 (2019), the Board approved amortization over a 34 month period from March 1, 2019 to December 31, 2021 to provide recovery in customer rates of any 2019 revenue shortfall/over-recovery associated with the March 1, 2019 rate implementation. The over-recovery of revenue was approximately $2,482,000 with accumulated amortization of $730,000. The net regulating liability for deferred costs – 2019 Cost Recovery Deferral at December 31, 2019 was approximately $1,752,000.

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 2019 the balance in this account was $168,740,000 (2018 - $160,047,000).

Based upon our analysis, nothing has come to our attention to indicate that changes in regulatory deferrals for 2019 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 2019 PEVDA was calculated at $833,658. This balance was transferred to the Rate Stabilization Account as a charge on March 31, 2019 in accordance with Order No. P.U. 43 (2009).

We confirm that the 2019 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 2019 OPEBVDA was calculated at $62,200. This balance was transferred to the Rate Stabilization Account as a charge on March 31, 2019 in accordance with Order No. P.U. 31 (2010).

We confirm that the 2019 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 2019 are as follows:

1. Made capital investments of $109 million of which over 46% 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. The Company implemented an ergonomics and soft tissue injury prevention program. Job demands analyses were completed for all operations positions, and training on the various components of the program started Company-wide;

7. The Company replaced its incident tracking and reporting system with a new Intelex incident management module. Intelex will allow improved reporting abilities, real time data analysis, and integration with other Intelex safety management modules already in service;

8. A safety consultant from The Engine Room provided safety leadership training to supervisors across the Company. Training included work observation coaching and one-on-one mentoring with supervisors;

9. Continued to build a relationship with the Forestry Safety Association of Newfoundland and Labrador ("FSANL") to increase awareness and prevent public contacts related to wood harvesting. A safety brochure has been developed by Newfoundland Power, and FSANL has agreed to supply a copy to people when acquiring cutting permits;

10. TakeCharge partnered with Dunsky Energy Consulting to conduct a conservation potential study to provide a high-level understanding of the energy conservation, demand response, fuel-switching and vehicle electrification opportunities that exist in the province. The results of the study are being used to develop the Company's next five-year conservation plan to be filed with the Board in 2020;

11. Work began on developing Newfoundland Power's Climate Change Adaptation Plan. The Company also initiated a gap analysis to verify its alignment with the national criteria established through the Canadian Electricity Association's Sustainable Electricity Brand;

12. An employee safety climate survey was conducted. This questionnaire, which is designed to assess the Company's safety culture, was consistent with the previous assessment in 2017, and the employee response rate was slightly higher. The survey responses in 2019 remain positive, with an overall average score of over 88%. The results will be further analyzed and an action plan will be developed in the first quarter of 2020;

13. Customer participation in the Company's self-service programs continued to increase. At the end of the year, 49% of customer accounts had subscribed to ebills, an increase of 2.4% from 2018;

14. The Company engaged CanSustain to compare Newfoundland Power's operations with the International Standard ISO 26000:2010 – Guidance on Social Responsibility. The standard addresses a broad range of environmental, social and governance indicators, and is the basis of the CEA utility sustainability program. Overall, the assessment indicated strong alignment. Full analysis of the results, and development of an action plan will be completed in the first quarter of 2020;

15. On track to comply with federal regulations regarding the removal of polychlorinated biphenyls ("PCBs") from specific substation equipment by 2025. In 2019 the Company replaced three power transformers and eight breakers;

16. Combined the office and service buildings in Burin. The new building improves operating efficiency and is more energy efficient;

17. The Company established its cybersecurity governance structure and clarified management roles and oversight processes. Preparation is ongoing for the 2020 implementation of a new system to coordinate access management for critical technology, and improvements to documentation of cybersecurity controls are continuing;

18. Meter reading performance continued to improve. 2019 was the second year of full Automated Meter Reading ("AMR"). Through ongoing technology improvements, there has been a further 28% reduction in customer bill estimates due to unavailable meter readings, compared to 2018;

19. The high-volume call answering system that drives Newfoundland Power's outage information phone line was replaced with a virtual cloud-based solution in the fourth quarter. The new system can handle more callers simultaneously and provides customers with address-specific outage information automatically based on the caller's phone number. It also provides improved message administration, combining pre-recorded messaging with text-to-speech capabilities;

20. A new Outage Management System ("OMS") was implemented in 2019. The new OMS integrates key operations and customer service applications. It allows the Company to more effectively manage outages and provide customers with detailed up-to-date information through the contact center, website and direct notifications; and

21. A new incident management system was launched. The new Intelex module will functionally replace the previous system and offer new and improved ways to manage and report on safety and environmental metrics.

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 2017	Actual 2018	Actual 2019	Plan 2019	Measure Achieved
Reliability	Outage Hours/Customer (SAIDI) – excluding Hydro loss of supply[1]	2.28	2.65	2.34	2.39	Yes
	Outage/Customer (SAIFI) – excluding Hydro loss of supply[1]	1.66	1.67	1.62	1.85	Yes
	Plant Availability (%)[2]	91.3	96.3	95.7	95.0	Yes
Customer Satisfaction	% of Satisfied Customers as measured by Customer Satisfaction Survey	86.5	85.6	85.8	85.6	Yes
	Call Centre Service Level (% per second)[3]	80/60	81/60	77/60	80/60	No
	Trouble Call Responded to Within 2 Hours (%)	87.0	85.0	81.0	85.0	No
Safety	All Injury/Illness Frequency Rate	0.7	0.9	0.4	0.9	Yes
Financial	Earnings (millions)[4]	$41.0	$41.2	$42.3	$40.9	Yes
	Gross Operating Cost/Customer[5]	$264	$225	$229	$232	Yes

[1] 2017 statistics exclude the impact of snow storms in March & December. 2018 statistics exclude the impact of wind storms in April & November and a Power Transformer failure in November. 2019 statistics exclude the impact of a wind storm in February, Hurricane Dorian in September and a snow storm in November.
[2] Excludes the hours of generation unit is out of service due to system disruptions and major plant refurbishment.
[3] Service level is based on calls answered in 60 seconds.
[4] Earnings applicable to common shares.
[5] Excluding conservation program costs, pension, OPEBs and early retirement program costs.

The following table compares whether the Company measures were achieved during the 2017, 2018, and 2019 years:

Category	Measure	Measure Achieved 2017	Measure Achieved 2018	Measure Achieved 2019
Reliability	Outage Hours/Customer (SAIDI) – excluding Hydro loss of supply	Yes	No	Yes
	Outage/Customer (SAIFI) – excluding Hydro loss of supply	Yes	Yes	Yes
	Plant Availability (%)	No	Yes	Yes
Customer Satisfaction	% of Satisfied Customers as measured by Customer Satisfaction Survey	No	No	Yes
	Call Centre Service Level (% per second)	Yes	Yes	No
	Trouble Call Responded to Within 2 Hours (%)	Yes	Yes	No
Safety	All Injury/Illness Frequency Rate	Yes	No	Yes
Financial	Earnings (millions)	Yes	Yes	Yes
	Gross Operating Cost/Customer	Yes	No	Yes

Grant Thornton
2020 Annual Financial Review of Newfoundland Power Inc.

Board of Commissioners of Public Utilities

Financial Consultants Report
2020 Annual Financial Review of
Newfoundland Power Inc.

Table of Contents

Restrictions, Qualifications and Independence

Purpose

This report was prepared for the Board of Commissioners of Public Utilities ("the Board") in Newfoundland and Labrador. The purpose of our engagement was to present our observations, findings and recommendations with respect to our 2020 annual financial review of Newfoundland Power Inc. ("the Company") (Newfoundland Power").

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 Access to Information and Protection of Privacy Act 2015 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 presents our observations, findings and recommendations with respect to our 2020 Annual Financial Review of Newfoundland Power. Below is a summary of the key observations and findings included in our report.

- The average rate base for 2020 was $1,181,897,000 which is an increase of $28,341,000 (2.5%) over the average rate base for 2019 of $1,153,556,000. The Company's calculation of the return on average rate base for 2020 was 7.04% (2019 – 6.97%) 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 2020 was $516,759,000 (2019 - $510,388,000). The Company's actual return on average common equity for the year ended December 31, 2020 was 8.93% (2019 – 8.79%). In Order No. P.U. 32 (2007), the Board ordered that if 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, the Company must file a report with its annual return explaining the facts and circumstances contributing to the difference. In 2019 the cost of common equity was 8.50% as per Order No. P.U. 2 (2019). The actual return on average common equity for 2020 was 8.93% as noted above. This return was within the 50-basis point limit and as such no report was required.

- Total actual capital expenditures (excluding capital projects carried forward from prior years) were 11.66% under budget in 2020. Total capital expenditures (including projects carried over from prior years) were over the approved budget on a net basis by $753,000 (0.63%). However, for each category of expenditure, the variances ranged from an over-budget of 9.63% to an under-budget of 100.00%.

- The Company experienced a 4.60% increase in revenue from rates in 2020 as compared to 2019. The increase is primarily due to higher wholesale electricity rates effective October 1, 2019. These factors were partially offset by the impact of lower electricity sales.

- Overall, net operating expenses increased by $7,634,000 from 2019 to 2020. Significant operating expense variances are discussed throughout our report. We conducted an examination of other costs including, depreciation, interest and income taxes and have noted that nothing has come to our attention to indicate that these costs for 2020 are unreasonable.

- During our review of non-regulated expenses, nothing came 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.

- The 2020 Pension Expense Variance Deferral Account ("PEVDA") operated in accordance with Order No. P.U. 43 (2009).

- The 2020 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 2020 the Company met six out of nine of its planned performance measures. The Company fell short of its targets in "Outage Hours/Customer(SAIDI)", "Outage/Customer (SAIFI)"and "Trouble Call Responded to Within 2 Hours", as discussed later in this report.

Introduction

This report to the Board presents our observations, findings and recommendations with respect to our 2020 Annual Financial Review of Newfoundland Power.

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

4. Review intercompany charges and assess compliance with Board Orders including requirements for additional reports pursuant to Order No. P.U. 19 (2003), Order No. P.U. 32 (2007), Order No. P.U. 43 (2009), and Order No. P.U. 13 (2013).

5. Examine the Company's 2020 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 2014 Depreciation Study and review the calculations of depreciation expense.

7. Review Minutes of Board of Directors' meetings.

8. Review the Company's initiatives 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 based on the nature 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 financial statements of the Company for the year ended December 31, 2020 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 11, 2021. 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

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

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 31, 2021, the Company filed a revised system of accounts as part of its 2020 Annual Report. In submitting these changes, the Company noted that the revisions were mainly due to the addition of two new accounts and some minor wording changes to improve the clarity and accuracy of account descriptions.

Based upon our review of the Company's financial records we have found that they are in compliance with the system of accounts approved 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, 2020 which is included on Return 3 of the annual report to the Board was calculated using the Asset Rate Base Method ("ARBM"). The average rate base for 2020 was $1,181,897,000 which is an increase of $28,341,000 (2.5%) over the average rate base for 2019 of $1,153,556,000. 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 2020; 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 2019 and 2020 (all figures shown are averages):

(000)'s	2020	2019
Net Plant Investment (average)		
Plant Investment	$ 1,987,608	$ 1,909,493
Accumulated Depreciation	(809,124)	(771,588)
CIAC's	(44,487)	(41,596)
	1,133,997	1,096,309
Additions to Rate Base (average)		
Deferred Charges *(a)*	90,916	90,842
Cost Recovery Deferral for Hearing Costs *(b)*	371	247
Cost Recovery Deferral – Conservation *(c)*	17,210	16,630
Customer Finance Programs *(d)*	2,296	2,477
Demand Management Incentive Account *(e)*	1,442	941
Weather Normalization Reserve *(f)*	960	3,586
	113,195	114,723
Deductions from Rate Base (average)		
Other Post-Employment Benefits *(g)*	64,265	59,452
Customer Security Deposits *(h)*	1,316	1,245
Accrued Pension Obligation *(i)*	5,182	5,060
Deferred Income Taxes *(j)*	11,386	7,488
Cost Recovery Deferral – 2019 Cost Recovery Deferral *(k)*	920	613
	83,069	73,858
Average Rate Base before Allowances	1,164,124	1,137,174
Rate Base Allowances		
Materials and Supplies	7,270	6,475
Cash Working Capital	10,503	9,907
	17,773	16,382
Average Rate Base	$ 1,181,897	$ 1,153,556

(a) The Company's rate base is determined using the ARBM which incorporates average deferred charges into the calculation of rate base. The total average deferred charges of $90,916,000 (2019 - $90,842,000) included in the 2020 rate base consists of average deferred pension costs of $90,862,000 (2019 - $90,751,000) and credit facility costs of $54,000 (2019 - $91,000). The Company has included a schedule of these costs in Return 8.

(b) In Order No. P.U. 2 (2019), the Board approved the 34-month amortization of $1,000,000 in estimated hearing costs related to the 2019/2020 General Rate Application, commencing March 1, 2019 through December 31, 2021. According to the Company, the actual hearing costs for the 2019/2020 General Rate Application were $329,728. The Company transferred $670,272 to the Rate Stabilization Account on March 31, 2019 representing the difference between actual of $329,728 and estimated costs of $1,000,000 as directed by the Board in Order No. P.U. 2 (2019) instead of a reduction in rate base in 2019. The 2020 average rate base includes an addition of $371,000 (average of $494,000 and $247,000 for 2019 and 2020 relating to these hearing costs).

(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.

- In 2013 the actual costs incurred and deferred were $2,937,000 ($2,085,000 after tax) resulting in annual amortization of $298,000 in 2014.
- In 2014 the actual costs incurred and deferred were $4,436,000 ($3,150,000 after tax) resulting in additional annual amortization of $450,000 to commence in 2015.
- In 2015 the actual costs incurred and deferred were $4,611,000 ($3,274,000 after tax) resulting in additional annual amortization of $468,000 to commence in 2016.
- In 2016 the actual costs incurred and deferred were $7,200,000 ($5,040,000 after tax) resulting in additional annual amortization of $720,000 to commence in 2017.
- In 2017 the actual costs incurred and deferred were $6,759,000 ($4,731,000 after tax) resulting in additional annual amortization of $676,000 to commence in 2018.
- In 2018 the actual costs incurred and deferred were $6,239,000 ($4,367,000 after tax) resulting in additional annual amortization of $624,000 to commence in 2019.
- In 2019 the actual costs incurred and deferred were $6,864,000 ($4,805,000 after tax) resulting in additional annual amortization of $686,000 to commence in 2020.
- In 2020 the actual costs incurred and deferred were $5,119,000 ($3,583,000 after tax).
- Included in the calculation of the average rate base for 2020 is $17,210,000 (2019 - $16,630,000) 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 2020 average rate base incorporates $2,296,000 (2019 - $2,477,000) related to these programs.

(e) In Order No P.U. 11 (2020), the Board approved the disposition of the 2019 balance of the Demand Incentive Account of $2,687,000 ($1,881,000 after tax) by means of a debit to the Rate Stabilization Account as of March 31, 2020. In Order No. P.U. 14 (2021), the Board approved the disposition of the 2020 balance of the Demand Incentive Account of $1,431,000 ($1,002,000 after tax) by means of a debit to the Rate Stabilization Account as of March 31, 2021. The 2020 average rate base incorporates $1,442,000 (2019 - $941,000) related to this account.

(f) During 2020, 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 an increase to the reserve of $5,654,000 in 2020 (2019 – $1,517,000 increase).

Other transfers:

i. $3,856,000 increase to the reserve related to the after-tax impact of the Degree Day Normalization Reserve Transfer (2019 – $1,347,000 decrease).
ii. $122,000 decrease to the reserve related to the after tax impact of the Hydro Production Equalization Reserve transfer (2019 - $4,307,000 decrease).

The net impact was a net decrease to the reserve of $9,388,000 (2019 - $4,137,000 increase). The ending balance in this reserve account totaled $3,734,000 compared to a balance of ($5,654,000) at December 31, 2019 (an average of ($960,000) for 2020) (2019 – ($3,586,000)). This represents a balance owed to customers.

(g) Other Post-Employment Benefits is equal to the difference, at December 31, 2020, between the OPEBs liability of $94,457,000 and the OPEBs asset of $27,718,000. The calculation of the 2020 average rate base of $64,265,000 is equal to the average of the December 31, 2020 net liability of $66,739,000 and the December 31, 2019 net liability of $61,791,000.

(h) Customer Security Deposits are comprised of security deposits received from customers for electrical services as outlined with the Board-approved Schedule of Rates, Rules and Regulations. The calculation of the 2020 average rate base incorporates $1,316,000 (2019 - $1,245,000) related to customer security deposits.

(i) The 2020 average rate base calculation incorporates $5,182,000 (2018 - $5,060,000) 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 2020 average rate base is ($2,956,000) and ($16,767,000) respectively. The remaining balance of the deferred income tax liability in the amount of $31,109,000 relates to capital assets. This results in an average balance for deferred income tax liability of $11,386,000 (2019 - $7,488,000).

(k) In Order No. P.U. 2 (2019), the Board approved the deferral over a 34-month period of a $2,482,000 (before tax) revenue surplus from March 1, 2019 rate implementation of rates. The 2020 average rate base includes a deduction of $920,000 (2019 - $613,000).

The net change in the Company's average rate base from 2019 to 2020 can be summarized as follows:

(000's)	**2020**	2019
Average rate base - opening balance	**$ 1,153,556**	$ 1,117,341
Change in average deferred charges and deferred regulatory costs	**471**	1,332
Average change in:		
Plant in service	**78,115**	75,078
Accumulated depreciation	**(37,536)**	(32,558)
Contributions in aid of construction	**(2,891)**	(3,122)
Weather normalization reserve	**(2,626)**	442
Other post-employment benefits	**(4,814)**	(4,604)
Future income taxes	**(3,898)**	(3,087)
Rate base allowances	**1,391**	1,982
Customer Finance Programs	**(181)**	499
Demand Management Incentive Acct	**501**	196
Other rate base components (net)	**(191)**	57
Average rate base - ending balance	**$ 1,181,897**	$ 1,153,556

Based upon the results of the above procedures we did not note any discrepancies in the calculation of the 2020 average rate base, and therefore conclude that the 2020 average rate base included in the Company's annual report to the Board is 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 2020 was 7.04% (2019 – 6.97%). 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. The return on average rate base is calculated in accordance with the methodology approved in Order No. P.U. 32 (2007).

The actual return on average rate base in comparison to the range of allowed return for each of the years from 2018 to 2020 is set out in the table below.

	2020	2019	2018
Actual Return on Average Rate Base	7.04%	6.97%	7.13%
Upper End of Range set by the Board	7.22%	7.19%	7.22%
Lower End of Range set by the Board	6.86%	6.83%	6.86%

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 2020 in Order No. P.U. 2 (2019). As noted above, the Company's actual return on average rate base for 2020 was 7.04% which was inside 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. 2 (2019), the Board reconfirmed its previous position as per Order No. P.U. 13 (2013) regarding the capital structure for Newfoundland Power 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 2020 as reported in Return 24 is as follows:

		2020 Average		2019	2018
		(000's)	**Percent**	Percent	Percent
Debt	**$**	**629,385**	**54.70%**	54.28%	54.53%
Preferred equity[1]		**4,425**	**0.39%**	0.78%	0.80%
Common equity		**516,759**	**44.91%**	44.94%	44.67%
	$	**1,150,569**	**100%**	100%	100%

(1) The Company's preferred shares were redeemed in 2020.

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 2020 test year in Return 26. The embedded cost of debt for 2020 was 5.98% which represents a 2 bps decrease from the 2019 embedded cost of debt of 6.00%.

Based on the information indicated above, we conclude that the capital structure included in the Company's annual report to the Board is in accordance with Order No. P.U. 2 (2019).

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, 2020 is included on Return 27 of the annual report to the Board. The average common equity for 2020 was $516,759,000 (2019 - $510,388,000). The Company's actual return on average common equity for 2020 was 8.93% (2019 – 8.79%).

Our procedures 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 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), Order No. P.U. 18 (2016), and Order No. P.U. 2 (2019); and,
- recalculated the rate of return on common equity for 2019 and ensured it was in accordance with established practice, Order No. P.U. 32 (2007) and Order No. P.U. 2 (2019).

In Order No. P.U. 32 (2007), the Board ordered that where in a given year the actual rate of ROE is greater than 50 bps above the test year calculation of the cost of equity for the same year, the Company must file a report with its annual return explaining the facts and circumstances contributing to the difference. Per Order No. P.U. 2 (2019) the approved cost of common equity for 2020 was 8.50%. The actual return on average common equity for 2020 was 8.93%. Therefore, the actual return on average common equity was within the 50-basis point limit and no additional reporting 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)	2020	2019	2018	2017
Net Income	**$ 43,577**	$ 42,892	$ 41,744	$ 41,526
Income Taxes	**11,893**	11,298	12,280	12,882
Interest on long term debt	**36,811**	35,375	35,788	35,013
Interest during construction	**(949)**	(1,933)	(951)	(1,025)
Other interest and amortization of discount costs	**842**	1,590	931	893
Total	**$ 92,174**	$ 89,222	$ 89,792	$ 89,289
Interest on long term debt	**$ 36,811**	$ 35,375	$ 35,788	$ 35,013
Other interest and amortization of discount costs	**842**	1,590	931	893
Total	**$ 37,653**	$ 36,965	$ 36,719	$ 35,906
Interest Coverage (times)	**2.4**	2.4	2.4	2.5

The above table shows that the interest coverage had not changed from 2018 to 2020.

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 2020 is 2.4 times.

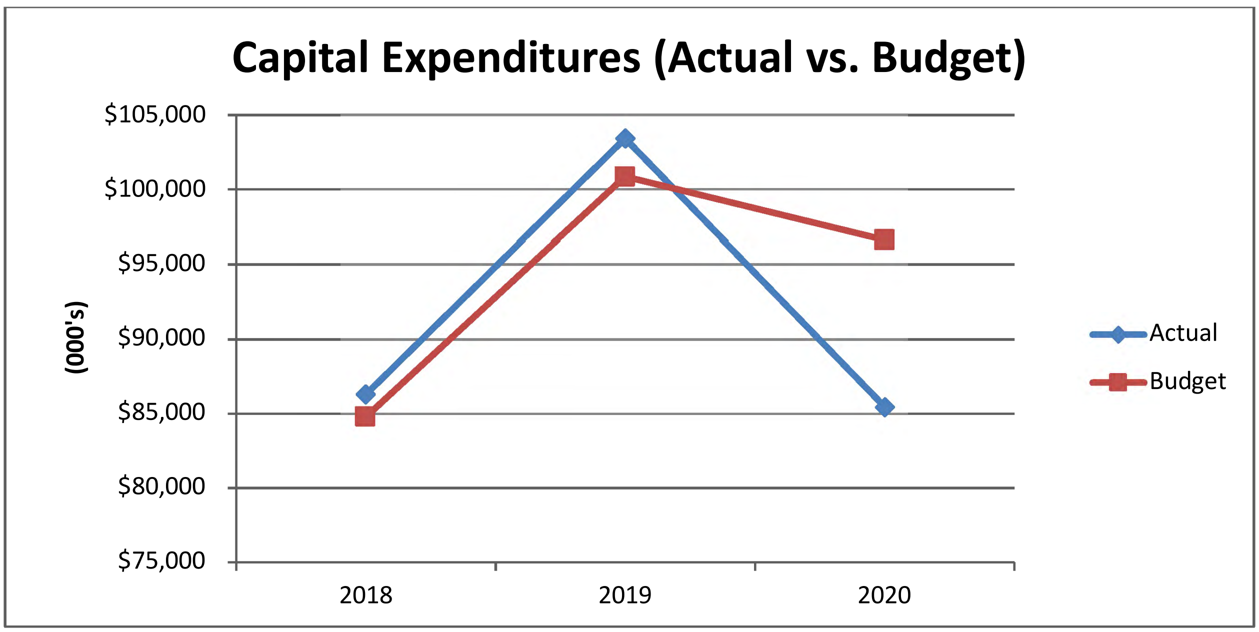
Capital Expenditures

Scope: ***Review the Company's 2020 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 2018 to 2020:

($000's)	2018	2019	2020	Notes
Actual	$ 86,285	$ 103,417	$ 85,447	1
Budget	$ 84,776	$ 100,856	$ 96,614	
Over (under) budget	1.78%	2.54%	(11.66%)	

Note 1: Total expenditures per the 2020 Capital Expenditure report includes the carryover amount of $11,539,000 for a total of $96,986,000. The carryover amount is made up of seven projects included in the following categories; $4,638,000 to Generation; $215,000 to Substation; $1,946,000 to Transmission; $2,492,000 to Distribution; $90,000 to General Property; $1,615,000 to Transportation; and $543,000 to Information Systems. According to the Company, these expenditures will occur in 2021.



The following table provides a summary of the capital expenditure activity in 2020 as reported in the Company's *"2020 Capital Expenditure Report":*

($000's)	Capital Budget			Actual Expenditures		
	Prior Years	2020	Total	Prior Years	2020	Total
2020 Capital Projects *(1)*	$ -	$ 96,614	$96,614	$ -	$85,447	$85,447
2019 Projects Carried to 2020 & Multi Year Projects:						
Relocate 114L	310	-	310	-	385	385
Cybersecurity Upgrades	398	-	398	271	146	417
Company Building Renovations *(2)*	1,374	-	1,374	1,182	543	1,725
Purchase Vehicles and Aerial Devices	3,990	-	3,990	2,648	1,575	4,223
Purchase Mobile Generation	13,915	-	13,915	13,179	78	13,257
System Upgrades	1,013	-	1,013	838	116	954
Human Resource Management System *(3)*	1,637	-	1,637	1,725	232	1,957
	22,637	-	22,637	19,843	3,075	22,918
Grand Total	**$ 22,637**	**$ 96,614**	**$ 119,251**	**$ 19,843**	**$88,522**	**$108,365**

Note 1 - Approved by Order No. P.U. 5 (2020).

Note 2 - The Company has noted that the unfavorable variance of the Company Building Renovations project is due to higher than expected tender pricing received for both the Salt Pond and Glovertown building renovations.

Note 3 - The variance in the Human Resource Management System was due to increased costs relating to COVID-19 safety protocols such as engaging with contractors remotely.

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

($000's)	2020 Budget *(1)*	2020 Actuals *(2)*	Variance	Carryover *(3)*	Variance Including Carryover	%
Generation - Hydro	$ 6,849	$ 2,124	($ 4,725)	$ 4,638	($ 87)	(1.27%)
Generation - Thermal	14,264	13,590	(674)	100	(574)	(4.02%)
Substation	15,204	14,517	(687)	215	(472)	(3.10%)
Transmission	9,933	8,387	(1,546)	1,946	400	4.03%
Distribution	44,623	42,405	(2,218)	2,492	274	0.61%
General property	3,841	4,108	267	90	357	9.29%
Transportation	7,859	6,477	(1,382)	1,615	233	2.96%
Telecommunications	108	112	4	-	4	3.70%
Information systems	9,820	10,067	247	543	790	8.04%
Unforeseen	750	-	(750)	-	(750)	(100.00%)
General expenses capitalized	6,000	6,578	578	-	578	9.63%
Total	**$ 119,251**	**$ 108,365**	**($ 10,886)**	**$ 11,639**	**$ 753**	**0.63%**

Note 1 - Includes prior years projects and current year budgeted amounts as there were projects incomplete at the previous year ends.
Note 2 - 2020 actuals include the total expense for projects carried forward from 2019.
Note 3 - Represents $11,639,000 in capital projects carried forward to 2021.

As indicated in the table, actual capital expenditures were less than the approved budget by $10,886,000 and when carryover amounts are considered, they were $753,000 (0.63%) higher. However, for each category of expenditure, the variances ranged from an over-budget of 9.63% for the general expenses capitalized category to an under-budget of 100.00% 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	$ 60
Petty Harbour Plant	3,325
Rattling Brook Plant Refurbishment	1,083
Substation Feeder Termination	215
Rebuild Transmission Lines	1,946
Trunk Feeders	2,050
Feeder Additions for Growth	442
Company Building Renovations	90
Purchase Vehicles and Aerial Devices	1,615
Application Enhancements	135
System Upgrades	408
Topsail Hydro Plant Refurbishment	170
Purchase Mobile Generation *(1)*	100
Total Carryover	**$ 11,639**

Note 1 – Carryover related to the Purchase Mobile Generation project from prior years.

The Company has provided detailed explanations on budget to actual variances in Appendix A of its "2020 Capital Expenditure Report".

Adherence to Capital Budget Application Guidelines

Based on our review, the Company's 2020 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% off the approved budget.

- 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 1.78% in 2018, 2.54% in 2019 and (11.56%) in 2020 resulting in no additional reporting requirements.

The allowance for unforeseen items account was not utilized in 2020.

<u>Capital Expenditure Reports</u>

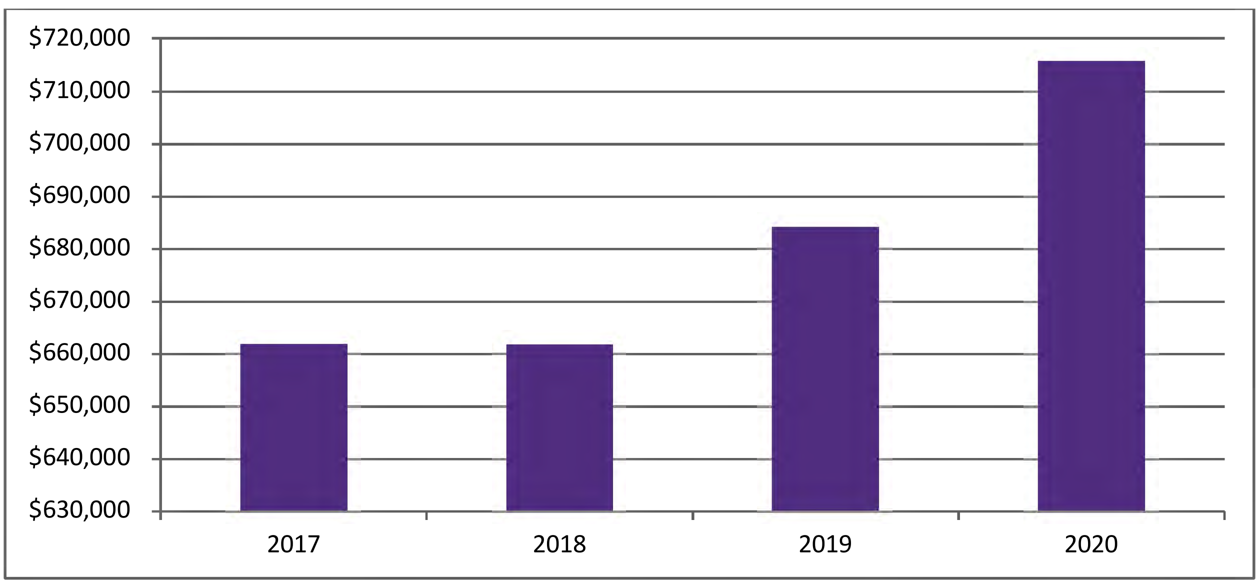
Confirmation was received from the Board that the Company filed quarterly Capital Expenditure reports for the 2020 calendar year.

Revenue from rates

Scope: ***Review the Company's 2020 revenue from rates in comparison to prior years and follow up on any significant variances.***

We have compared the actual revenues from rates for 2017 to 2020 to assess any significant trends. The results of this analysis of revenue by rate class are as follows:

($000's)	2017	2018	2019	2020
Residential	$ 422,237	$ 419,389	$ 432,272	$ 458,433
General Service				
0-100 kW	88,507	90,364	93,038	93,282
110-1000 kVA	95,565	97,338	101,397	105,418
Over 1000 kVA	37,099	35,725	37,916	38,643
Streetlighting	16,149	16,255	16,664	16,983
Discounts forfeited	2,327	2,643	2,892	2,868
Revenue from rates	$ 661,884	$ 661,714	$ 684,179	$ 715,627
Year over year percentage change	0.08%	-0.03%	3.39%	4.60%



The above graph demonstrates that the Company has seen a 4.60% increase in revenue from rates in 2020 as compared to 2019. The increase is primarily due to higher wholesale electricity rates effective October 1, 2019. These factors were partially offset by the impact of lower electricity sales.

The comparison by rate class of 2020 actual revenues to 2020 budget is as follows:

($000's)	2019	2020	2020 Plan	Actual - Plan Variance	Variance %
Residential	$ 432,272	$ 458,433	$ 423,434	$ 34,999	8.27%
General Service					
0-100 kW	93,038	93,282	92,409	873	0.94%
110-1000 kVA	101,397	105,418	100,840	4,578	4.54%
Over 1000 kVA	37,916	38,643	38,725	(82)	(0.21%)
Streetlighting	16,664	16,983	16,483	500	3.03%
Discounts forfeited	2,892	2,868	2,698	170	6.30%
Total revenue from rates	$ 684,179	$ 715,627	$ 674,589	$ 41,038	6.08%

We have also compared the 2020 budget energy sales in GWh to the actual sold in 2020:

(GWh)	2019	2020	2020 Plan	Actual - Plan Variance	Variance %
Residential	3,559.8	3,547.0	3,567.8	(20.8)	(0.58%)
General Service					
0-100 kW	797.6	749.4	808.2	(58.8)	(7.28%)
110-1000 kVA	1,024.2	990.2	1,045.5	(55.3)	(5.29%)
Over 1000 kVA	432.0	410.1	456.9	(46.8)	(10.24%)
Streetlighting	33.0	32.3	32.4	(0.1)	(0.31%)
Total	5,846.6	5,729.0	5,910.8	(181.8)	(3.08%)

Actual 2020 revenue from rates was higher than 2020 Plan with an overall increase in actual sales of $41,038,000 (6.08%) from the 2020 Plan due to increased rates as of October 1, 2019, partially offset by lower electricity sales. There was a 3.08% decrease in GWh sold in 2020 compared to 2020 Plan was primarily due to the lower average consumption by commercial customers as a result of the pandemic. The largest variance in revenue can be seen in the Residential, 110-1000 kVA, and the 0 – 100 kW class where revenues increased by $34,999,000 (8.27%), $4,578,000 (4.54%), and $873,000 (0.94%), 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.***

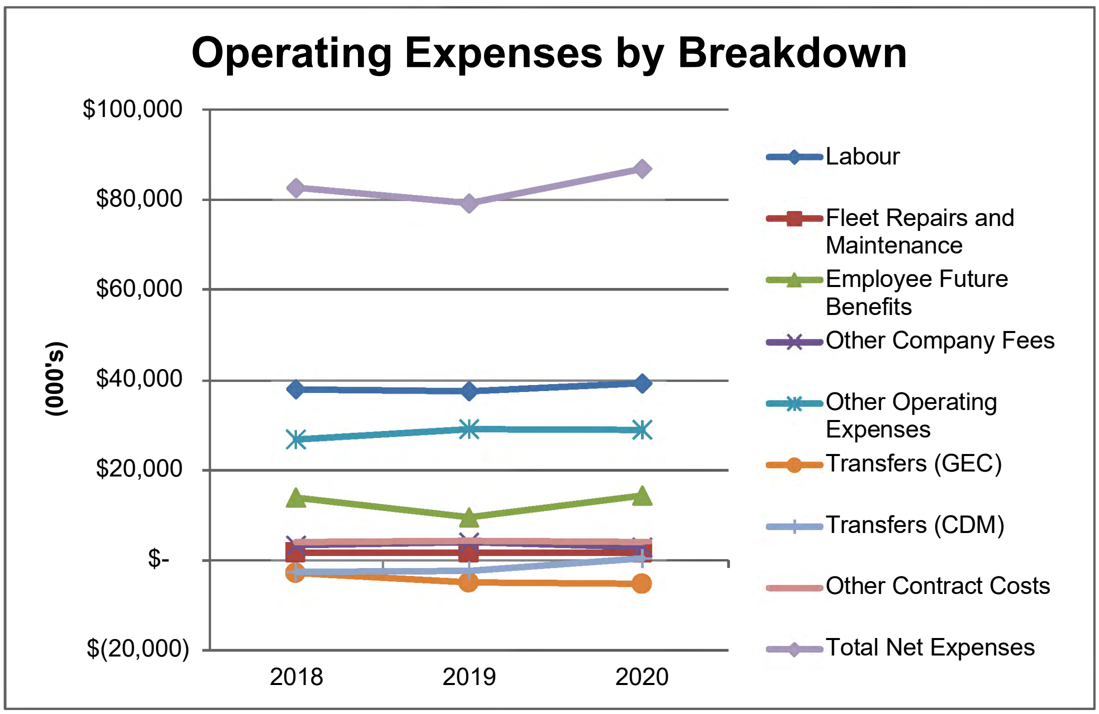
The below table provides details of operating and general expenses (including non-regulated expenses) by "breakdown" for 2018, 2019, and 2020.

(000's)	Actual 2020	Actual 2019	Actual 2018	Variance 2020-2019
Labour	$ 40,652	$ 38,603	$ 39,095	$ 2,049
Reclass OPEB labour cost	(1,290)	(1,041)	(1,125)	(249)
Total labour	39,362	37,562	37,970	1,800
Vehicle expense	1,725	1,681	1,682	44
Operating materials	1,301	1,361	1,511	(60)
Inter-company charges	2,277	2,058	1,847	219
Plants, Subs, System Oper & Bldgs	3,484	3,267	2,812	217
Travel	638	1,142	1,127	(504)
Tools and clothing allowance	1,156	1,289	1,254	(133)
Miscellaneous	1,999	2,005	1,619	(6)
Conservation	2,172	2,813	2,732	(641)
Taxes and assessments	1,116	1,156	1,286	(40)
Uncollectible bills	2,290	1,980	1,490	310
Insurance	1,698	1,397	1,306	301
Severance & other employee costs	126	132	68	(6)
Education, training, employee fees	275	444	403	(169)
Trustee and directors' fees	673	518	481	155
Other company fees	2,944	4,058	3,379	(1,114)
Stationary & copying	246	257	224	(11)
Equipment rental/maintenance	656	790	784	(134)
Communications	2,786	2,803	2,822	(17)
Advertising	1,264	1,581	1,443	(317)
Vegetation management	2,306	2,042	1,692	264
Computing equipment & software	2,199	1,830	1,628	369
Total Other	33,331	34,604	31,590	(1,273)
Pension & early retirement program	7,864	3,335	7,726	4,529
OPEB's	6,528	6,241	6,194	287
Total employee future benefits	14,392	9,576	13,920	4,816
Total gross expenses	87,085	81,742	83,480	5,343
Transfers (GEC)	(5,175)	(4,913)	(2,781)	(262)
CDM amortization	5,578	4,597	3,706	981
Other contract expenses	4,120	4,353	4,081	(233)
Deferred CDM program costs	(5,118)	(6,864)	(6,239)	1,746
Deferred regulatory costs	353	294	341	59
Total net expenses	**$ 86,843**	**$ 79,209**	**$ 82,588**	**$ 7,634**

Overall, net operating expenses increased by $7,634,000 from 2019 to 2020. 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 2020 are unreasonable.

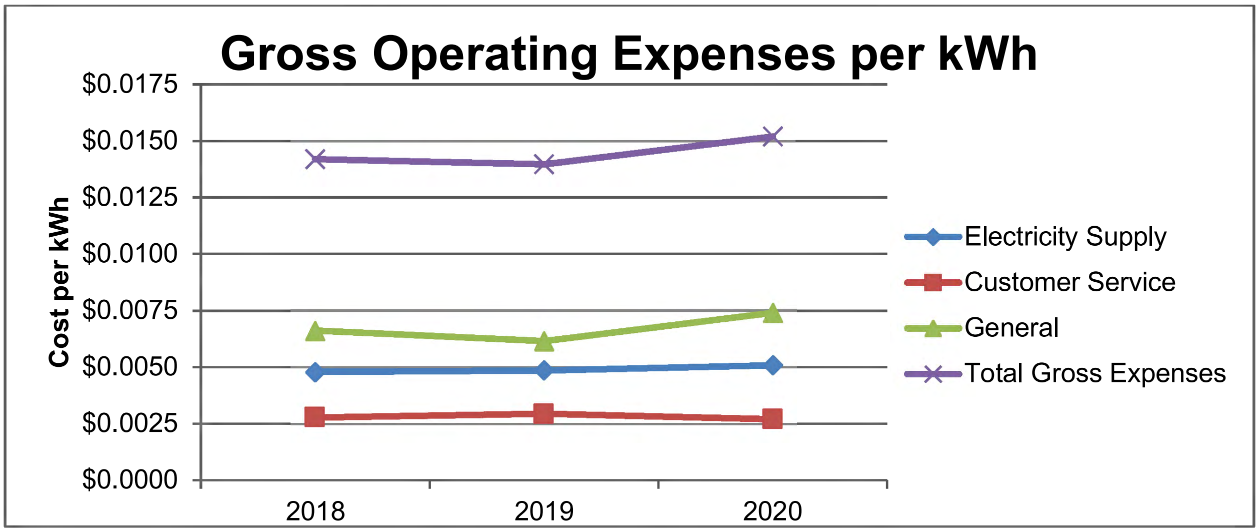
Our detailed review of operating expenses was conducted using the breakdown as documented in the above table. It should also be noted that our review is based upon gross expenses before allocation to GEC and CDM. The following table and graph show the trend in net operating expenses by breakdown for the period 2018 to 2020.

	Actual		
(000's)	**2020**	**2019**	**2018**
Labour	$ 39,362	$ 37,562	$ 37,970
Fleet Repairs and Maintenance	1,725	1,681	1,682
Employee Future Benefits	14,392	9,576	13,920
Other Company Fees	2,944	4,058	3,379
Other Operating Expenses	29,016	29,159	26,870
Transfers (GEC)	(5,175)	(4,913)	(2,781)
Transfers (CDM)	460	(2,267)	(2,533)
Other Contract Costs	4,119	4,353	4,081
Total Net Expenses	**$ 86,843**	**$ 79,209**	**$ 82,588**



The relationship of operating expenses to the sale of energy (expressed in kWh) from 2018 to 2020 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
2018	5,876,100	$28,185	$0.0048	$16,429	$0.0028	$38,866	$0.0066	$83,480	$0.0142
2019	5,846,600	$28,473	$0.0049	$17,298	$0.0030	$35,971	$0.0062	$81,742	$0.0140
2020	5,729,000	$29,144	$0.0051	$15,555	$0.0027	$42,386	$0.0074	$87,085	$0.0152



The table and graph show that total gross expenses per kWh have increased by approximately 8.7% compared to 2019.

There was an increase in General Costs of $6.4 million, with a decrease in Customer Service Costs of $1.7 million and an increase in Electricity Supply Costs of $0.7 million. The results of our review of the individual significant expense categories variances are noted on the next page.

Salaries and Benefits (including executive salaries)

A detailed comparison of the number of full-time equivalent (FTE) employees by category for 2018 to 2020 (including 2020 plan) is as follows:

	Actual 2020	**Plan 2020**	Actual 2019	Actual 2018	**Actual - Plan**	**Actual 2020-2019**
Executive Group	**6.0**	**6.0**	6.2	5.7	0.0	(0.2)
Corporate Office	**21.6**	**21.7**	20.8	19.8	(0.1)	0.8
Finance and IT	**96.6**	**99.6**	93.5	91.6	(3.0)	3.1
Engineering and Operations	**382.7**	**389.1**	383.2	372.9	(6.4)	(0.5)
Customer Relations	**70.6**	**73.9**	72.8	78.8	(3.3)	(2.2)
	577.5	**590.3**	576.5	568.8	(12.8)	1.0
Temporary employees	**34.0**	**42.3**	39.7	50.4	(8.3)	(5.7)
Total	**611.5**	**632.6**	616.2	619.2	(21.1)	(4.7)

The overall number of FTE's in 2020 compared to 2019 decreased by 4.7. The budgeted number of FTEs in the 2020 Plan was 632.6 versus actual of 611.5. The variances between 2020, 2020 Plan, and 2019 are the result of the following:

- Finance and Information Technology is lower than plan due to delayed hires as a result of COVID-19. Additionally, the increase from 2019 is due to the impact of hires in late 2019 and additional positions in Regulatory.
- Engineering and operations is lower than plan due to delayed hires as a result of COVID-19. However, 2020 is fairly consistent with 2019.
- Customer relations is lower than plan and 2019 due to delayed hires as a result of COVID-19 partially offset by a shift from temporary to regular employees.
- Temporary employees are lower than plan and 2019 primarily due to a shift from temporary to regular employees and delayed hires in 2020 as a result of COVID-19.

An analysis of salaries and wages by type of labour and by function from 2018 to 2020 is as follows:

(000's)	**Actual 2020**	Actual 2019	Actual 2018	**Variance 2020-2019**
Type				
Internal labour *(1)*	**$ 69,028**	$ 66,023	$ 65,090	$ 3,005
Overtime *(2)*	**5,886**	6,568	6,568	(682)
	74,914	72,591	71,658	2,323
Contractors *(3)*	**12,510**	17,523	15,409	(5,013)
	$ 87,424	$ 90,114	$ 87,067	$ (2,690)
Function				
Operating *(4)*	**$ 40,652**	$ 38,603	$ 39,095	$ 2,049
Capital and miscellaneous *(5)*	**46,772**	51,511	47,972	(4,739)
Total	**$ 87,424**	$ 90,114	$ 87,067	$ (2,690)
Year over year percentage change	**-2.99%**	3.50%	3.54%	

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 2020 were $2,690,000 (2.99%) lower than 2019.

Note 1 - Internal labour costs in 2020 were higher than 2019 due to higher corporate costs and inflationary increases. This increase was partially offset by delayed hires as a result of COVID-19.

Note 2 - Overtime labour for 2020 was lower than 2019 due to lower overtime associated with capital distribution work, capital generation work, and capital substation work. This decrease was partially offset by overtime associated with restoration efforts required following storms.

Note 3 - Contract labour for 2020 was lower than 2019 due to lower labour for transmission rebuilds and deficiencies, third party work for telecommunication companies, and capital distribution work.

Note 4 - Operating labour for 2020 was higher than 2019 due to increased operating labour reflects, higher corporate costs, restoration efforts required following storms, and inflationary increases and additional positions in Regulatory.

Note 5 - Capital and miscellaneous labour for 2020 was lower than 2019 due to lower contract labour for transmission rebuilds & deficiencies, third party work for telecommunication companies, and capital distribution work.

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 2018 to 2020 are included in the table below:

Salary Cost Per FTE	**Actual 2020**	Actual 2019	Actual 2018	**Variance 2020-2019**
Total reported internal labour costs	**$ 69,028**	$ 66,023	$ 65,090	$ 3,005
Benefit costs (net)	**(9,563)**	(8,926)	(8,939)	(637)
Other adjustments	**(1,693)**	(1,126)	(725)	(567)
Base salary costs	**57,772**	55,971	55,426	1,801
Less: executive compensation	**(1,936)**	(1,938)	(1,693)	36
Base salary costs (excluding executive)	**$ 55,836**	$ 54,033	$ 53,733	$ 1,837
FTE's (including executive members)	**611.5**	616.2	619.2	
FTE's (excluding executive members)	**607.5**	612.2	615.5	
Average salary per FTE	**94,476**	90,833	89,512	
% increase	**4.01%**	1.48%	0.81%	
Average salary per FTE (excluding executive members)	**91,912**	88,261	87,300	
% increase	**4.14%**	1.10%	1.40%	

The above analysis indicates that the rate of increase in average salary per FTE excluding executive members for 2020 has increased from 2019, and 2019 decreased from 2018.

Negotiated wage increases in the Company's collective agreement included a 2% increase effective January 1, 2020. According to the Company, the average salary increase of 4.2% is a result of multiple factors as follow:

- The COVID-19 pandemic caused delays in the hiring of temporary positions which impacted Temporary FTE's. This reduction in Temporary FTEs had an overall impact of increasing the average salary per FTE.

- Corporate Costs increased in 2020 compared to 2019. Corporate costs consist of OPEBs, Payroll Taxes, the Employer Portion of CPP & EI, and Employee Benefits. For example, in 2020, increased corporate costs accounted for an increase in the average salary per FTE metric of approximately 1.8%.

Therefore, a combination of increased benefit-related costs and lower temporary employees resulted in an increase in the overall average salary per FTE in 2020 versus 2019.

Short Term Incentive (STI) Program

The following table outlines the actual results for 2018 to 2020 and the targets set for 2020:

Measure	Target 2020	Actual 2020	Actual 2019	Actual 2018
Controllable Operating Costs/Customer	**$ 238.00**	$ 237.70	$ 231.00	$ 225.10
Earnings	**$ 42.1M**	$ 43.2M	$ 42.3M	$ 41.2M
Cash Flow from Operating Activities	**$ 108.7M**	$ 136.8M	$ 111.2M	$ -
Reliability - Duration of Outages (SAIDI)	**2.37**	2.98	2.34	2.65
Customer Satisfaction - % Satisfied	**85.8%**	87.6%	85.8%	85.6%
Injury Frequency Rate	**0.74**	0.74	0.37	-
Regulatory Performance	**-**	-	-	150%

According to the Company, reliability targets and results exclude interruptions which are Hydro related and those which meet the Institute of Electrical and Electronics Engineers (IEEE) definition of significant events. 2019 STI results were adjusted to remove the impact of the severe weather conditions in February, September and November. In 2019 the 'regulatory performance' measure was replaced by the 'cash flow from operating activities' measure.

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	70%	30%
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 2020 is established as a percentage of base pay for the three employee groups. For 2020, all measures were met besides "Reliability- Duration of Outages (SAIDI)" which was above target.

The following table illustrates the target as a percentage of base pay together with the actual STI payouts for 2018 to 2020:

	Target 2020	Actual 2020	Target 2019	Actual 2019	Target 2018	Actual 2018
President	50%	64.44%	50%	70.00%	50%	60.30%
Executive	35% - 40%	46.86%	35% - 40%	50.42%	35%-40%	47.04%
Directors	15%	19.73%	15%	17.94%	15%	18.28%

STI actual payout rates for 'President' and 'Executive' employee groups are lower than the prior year with the 'Director' group being higher and each payout rate exceeding targets consistent with 2019 and 2018.

In dollar terms, the STI payouts for 2018 to 2020 are as follows:

	Actual 2020	Actual 2019	Actual 2018	Variance 2020-2019
President	**$ 265,000**	$ 287,000	$ 230,000	$ (22,000)
Executive	**402,000**	416,000	346,000	(14,000)
Directors	**357,800**	311,000	296,200	46,800
Total	**$ 1,024,800**	$ 1,014,000	$ 872,200	$ 10,800
Year over Year % change	**1.07%**	16.26%	-19.24%	

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 2020, the non-regulated portion (before tax adjustment) was $299,085 (2019 - $344,832).

Executive Compensation

The following table provides a summary and comparison of executive compensation for 2018 to 2020:

	Base Salary	Short Term Incentive	Other	Total
2020				
Total executive group	$ 1,269,105	$ 667,000	$ 1,339,435	$ 3,275,540
Average per executive (4)	**$ 317,276**	**$ 166,750**	**$ 334,859**	**$ 818,885**
2019				
Total executive group	$ 1,235,000	$ 703,000	$ 421,412	$ 2,359,412
Average per executive (4)	**$ 308,750**	**$ 175,750**	**$ 105,353**	**$ 589,853**
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**
% Average change 2020 vs 2019	2.76%	(5.12%)	217.84%	38.83%
Per executive % average change 2020 vs 2019	2.69%	(5.40%)	68.54%	27.97%

Base salary for the executive group in 2020 increased by 2.76% from 2019. In 2020, while there was changeover within the executive positions throughout the year, four executives held positions for the entire year, resulting in 4 FTE. Therefore, this is comparable to 2019 even with the changes in executive positions (i.e. retirements and the promotion of current employees into different executive positions).

Other compensation for the executive group in 2020 increased from 2019, primarily due to a retention incentive pay to the retiring CEO as well as a significant increase in Performance and Restricted Share Unit Payouts. STI payouts and performance share unit payouts were agreed to the Board of Directors' minutes.

Company Pension Plan

For 2020, we reviewed the accounts supporting the gross charge of $7,864,000 of pension expense for the Company. A detailed comparison of the components of pension expense for 2018 to 2020 is below:

	Actual 2020	Actual 2019	Actual 2018	Variance 2020-2019
Pension expense per actuary	**$ 4,757,000**	$ 639,000	$ 5,163,000	$ 4,118,000
Pension uniformity plan (PUP)/supplemental employee retirement program (SERP)	**402,000**	347,000	501,000	55,000
Group RRSP @ 2%	**340,000**	315,000	289,000	25,000
Individual RRSP's	**2,371,000**	2,055,000	1,790,000	316,000
Less: Refunds (net of other expenses)	**(6,000)**	(21,000)	(17,000)	15,000
Total	**$ 7,864,000**	$ 3,335,000	$ 7,726,000	$ 4,529,000
Year over year percentage change	**135.80%**	(56.83%)	(10.94%)	

Overall, pension expense for 2020 is higher than 2019 primarily due to higher current service costs and higher amortization of net actuarial losses as a result of a decrease in the discount rate.

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 increased by 15.9% in 2020.

The employer's portion of the contributions to the Group RRSP is calculated as 2.0% (increased to 2% as of May 2019) of the base salary paid to the plan participants. Individual RRSP contributions increased as a result of a plan amendment which increased the contribution rate from 5.75% to 6.25% as of May 2019. New hires are added to the Individual RRSP Plan whereas the majority of retirements are out of the Group RRSP Plan. The increase in Group RRSP contributions made by the employer was primarily the result of a plan amendment which increased the contribution rate from 1.5% to 2.0% as of May 2019, which was partially offset by retirements.

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 2018 to 2020 are as follows:

(000's)	Actual 2020	Actual 2019	Actual 2018	Variance 2020-2019
Accrued OPEBs	**$ 4,191**	$ 3,657	$ 3,648	$ 534
Amortization of transitional balance	**3,504**	3,504	3,504	-
Amount capitalized	**(1,167)**	(920)	(958)	(247)
Total	**$ 6,528**	$ 6,241	$ 6,194	$ 287

The increase in OPEB's expense from 2019 to 2020 is primarily due to an increase in service costs.

Intercompany Charges

Our review of intercompany charges included the following specific procedures:

- assessed the Company's compliance with Order Nos. P.U. 19 (2003), P.U. 32 (2007), P.U. 43 (2009), and P.U. 13 (2013);
- compared intercompany charges for the years 2019 to 2020 and investigated any unusual fluctuations;
- reviewed detailed listings of charges for 2020 and investigated any unusual items;
- vouched a sample of transactions for 2020 to supporting documentation;
- assessed the appropriateness of the amounts being charged; and
- reviewed the methodology developed by Fortis Inc. ("Fortis") in 2008 to allocate recoverable expenses to its subsidiaries.

The following table summarizes intercompany transactions from 2018 to 2020 for charges to and from Newfoundland Power:

	Actual 2020	Actual 2019	Actual 2018	Variance 2019-2018
Charges from related companies				
Regulated	**$ 220,017**	$ 339,937	$ 1,121,634	$ (119,920)
Non-Regulated	**2,587,867**	2,360,484	2,101,634	227,383
Total	**$ 2,807,884**	$ 2,700,421	$ 3,223,268	$ 107,463
Charges to related companies	**$ 459,166**	$ 1,214,048	$ 643,394	$ (754,882)

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

We reviewed Fortis'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 2020. Fortis estimated its net pool of operating expenses for 2020 based on the 2021-2025 business plan and is billed quarterly.

Actual recoverable expenses were determined to be $2,277,000 and are summarized as follows:

2020 Recoverable Expenses from Fortis Inc.

	Amount	
Staffing and Staffing Related	$1,602,000	Non-regulated
Director Fees and Travel	170,000	Non-regulated
Consulting and Legal fees	119,000	Non-regulated
Trustee Agent Fees	20,000	Regulated
Annual Meeting Expenses	41,000	Non-regulated
Insurance (D&O)	43,000	Non-regulated
Other Costs	282,000	Non-regulated
	2,277,000	
Less amounts previously billed:		
Q1 2020	855,000	
Q2 2020	475,000	
Q3 2020	463,000	
Q4 2020 balance owing	$ 484,000	

As detailed above, trustee agent fees for $20,000 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. There were additional invoices of $467,723 received directly from Fortis during 2020 for total Fortis charges of $2,744,723 ($2,277,000+$467,723), of which $156,856 were regulated and $2,587,867 were non-regulated. 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, as well as other related parties. The following table summarizes the various components of the regulated intercompany transactions for 2018 to 2020 with Fortis:

(Regulated)	Actual 2020	Actual 2019	Actual 2018	Variance 2020-2019
Charges from Fortis Inc.				
Trustee fees and share plan costs	**$ 20,000**	$ 27,000	$ 25,000	$ (7,000)
Miscellaneous	**136,856**	208,765	941,488	(71,909)
Staff Charges	**-**	40,884	92,711	(40,884)
	$ 156,856	$ 276,649	$ 1,059,199	$ (119,793)
Year over year percentage change	**(43.30%)**	(73.88%)	564.65%	
Charges to Fortis Inc.				
Postage and couriers	**$ 1,640**	$ 2,181	$ 3,165	$ (541)
Staff charges	**23,546**	51,573	27,471	(28,027)
Miscellaneous	**58,704**	31,561	97,880	27,143
	$ 83,890	$ 85,315	$ 128,516	$ (1,425)
Year over year percentage change	**(1.67%)**	(33.62%)	24.67%	

The most significant fluctuations from our analysis of regulated charges from Fortis are a decrease in the staff charges account of $40,884 and a decrease in the miscellaneous account of $71,909. According to the Company, these fluctuations are due to a Fortis employee on secondment returning to Fortis in March 2019 and a 2018 Short-Term Incentive Payment to a former CEO in Quarter 1 of 2019, respectively.

The most significant fluctuations from our analysis of regulated charges to Fortis are a decrease in staff charges of $28,027 and an increase in miscellaneous charges of $27,143. These fluctuations are due to the 2019 labour expenses associated with three Newfoundland Power employees working on a Business Development Project for Fortis Inc. and a 2019 Short-Term Incentive Payment paid in 2020 to three employees that left Fortis to join Newfoundland Power, respectively.

The following table provides a summary and comparison of the non-regulated intercompany transactions for 2018 to 2020:

(Non-Regulated)	Actual 2020	Actual 2019	Actual 2018	Variance 2020-2019
Charges from Fortis Inc.				
Director's fees and travel	**$ 170,000**	$ 178,000	$ 139,000	$ (8,000)
Staff charges	**1,602,000**	1,294,000	1,054,000	308,000
Miscellaneous	**815,867**	888,484	908,634	(72,617)
	$ 2,587,867	$ 2,360,484	$ 2,101,634	$ 227,383

Staff charges have increased from 2019 by $308,000 primarily due to new executive positions added at Fortis Inc. in 2020, including stock-based compensation.

Miscellaneous charges decreased by $72,617. According to the Company this is because there was an approximate $50,000 decrease in travel expenses due to the COVID-19 pandemic as well as approximately $20,000 less in communications costs.

The following table provides a summary and comparison of the other intercompany transactions for 2018 to 2020:

Intercompany Transactions (Other)	Actual 2020	Actual 2019	Actual 2018	Variances 2020-2019
Charges to Fortis Ontario Inc.				
Staff charges	**$ 105,907**	$ 390,837	$ 371,640	$ (284,930)
Miscellaneous	**219,076**	326,592	35,193	(107,516)
	$ 324,983	$ 717,429	$ 406,833	$ (392,446)
Charges from Fortis Ontario Inc.				
Miscellaneous	**$ -**	$ 4,875	$ -	$ (4,875)
Charges to Maritime Electric				
Staff charges	**$ 997**	$ 276,106	$ -	$ (275,109)
Miscellaneous	**36,305**	78,496	550	(42,191)
	$ 37,302	$ 354,602	$ 550	$ (317,300)
Charges from Maritime Electric				
Miscellaneous	**$ 11,406**	$ 6,193	$ 15,258	$ 5,213
Charges to Central Hudson Gas & Electric				
Staff charges	**$ -**	$ 6,321	$ -	$ (6,321)
Charges from Central Hudson Gas & Electric				
Miscellaneous	**$ 4,068**	$ 10,190	$ 5,705	$ (6,122)

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Intercompany Transactions (Other) Cont'd.	Actual 2020	Actual 2019	Actual 2018	Variances 2020-2019
Charges to Belize Electric Company Ltd.				
Staff charges	**$ 12,991**	$ 35,226	$ 91,553	$ (22,235)
Miscellaneous	**-**	475	-	(475)
	$ 12,991	$ 35,701	$ 91,553	$ (22,710)
Charges to FortisAlberta Inc.				
Miscellaneous	**$ -**	$ 5,000	$ 4,980	$ (5,000)
Charges from FortisAlberta Inc.				
Miscellaneous	**$ 37,612**	$ 37,612	$ 38,073	$ -
Charges to FortisBC Inc./ FortisBC Holdings				
Miscellaneous	**$ -**	$ 9,680	$ 9,370	$ (9,680)
Charges from FortisBC Inc./ Fortis BC Holdings				
Miscellaneous	**$ 10,075**	$ 4,418	$ 3,399	$ 5,657
Charges to Fortis Turks and Caicos				
Miscellaneous	**$ -**	$ -	$ 1,592	$ -

The most significant fluctuations from our analysis of other intercompany charges for 2020 compared to 2019 are as follows:

- Staff charges to Fortis Ontario Inc. decreased by $284,930 in 2020. A large portion ($249,000) of this reduction was due to a senior staff member accepting a position with Fortis Ontario Inc. and leaving the Company in April 2020. In addition, due to the COVID-19 pandemic, there were no travel expenses for the President or other employees who serve on the Fortis Ontario and Wataynikaneyap Power Board of Directors;
- Miscellaneous charges to Fortis Ontario Inc. decreased by $107,516 due to a 2019 Special Payment of $163,200 to a senior staff member. This was offset by a $11,200 loan and a $31,377 Pension Expense for the same employee in 2020;
- Staff charges to Maritime Electric were $275,109 lower and miscellaneous charges were $42,191 lower in 2020 than in 2019. These decreases were due to the Hurricane Dorian Response for Maritime Electric that occurred in 2019;
- Staff Charges to Central Hudson Gas & Electric decreased by $6,321 in 2020. This is because the Company's Director of Technology assisted with an IT Project at Central Hudson Gas & Electric in 2019 but not in 2020.
- Miscellaneous charges from Central Hudson Gas & Electric decreased by $6,122 in 2020. This is because the COVID-19 pandemic resulted in less travel expenses incurred by Board of Director members from Central Hudson;
- Staff charges to Belize Electric Company Ltd. decreased by $22,235 primarily because the COVID-19 pandemic resulted in no travel expenses incurred by Newfoundand Power employees in relation to work with Belize Electric Company Ltd;
- Miscellaneous charges to FortisAlberta Inc. decreased by $5,000 in 2020 because the Conference Board of Canada charges for FortisAlberta Inc. were not processed until the first quarter of 2021;
- Miscellaneous charges to FortisBC Inc./Fortis BC Holdings decreased by $9,680 in 2020 because the Conference Board of Canada charges for FortisBC Inc./Fortis BC Holdings were not processed until the first quarter of 2021; and
- Miscellaneous charges from FortisBC Inc/ Fortis BC Holdings increased by $5,657 in 2020 because of $10,000 in SERP expenses pertaining to a former employee, offset by $4,400 in Canadian Hydropower Association dues in 2019.

The Company entered into the following short-term loan agreements with related parties during the year:

Loans to Newfoundland Power

Lender	Maximum Amount Borrowed	Date Borrowed	Date Repaid	Amount Repaid[2]	Interest Rate	Total Interest Cost
Fortis Inc.	$ 60,000,000	December 20, 2019	January 29, 2020[1]	$ 60,000,000	2.478750%	$ 139,408
Fortis Inc.	$ 60,000,000	January 20, 2020	March 5, 2020	$ 60,000,000	2.468750%	$ 107,761
Fortis Inc.	$ 68,000,000	February 20, 2020	March 20, 2020	$ 48,000,000	2.397500%	$ 95,112
Fortis Inc.	$ 20,000,000	March 20, 2020[3]	April 22, 2020	$ 20,000,000	2.080000%	$ 36,460
						$ 378,741

1. On December 31, 2019, Newfoundland Power re-paid $9,500,000 plus $44,821.23 interest based on 2.396250%.
2. Excludes interest paid on loan.
3. On March 20, 2020, Newfoundland Power re-financed $20,000,000 outstanding from previous $68,000,000 loan at a lower interest rate. Interest Rate 2.08% from March 20 to April 20, 2020 and 1.03% for April 21 and April 22, 2020.

The interest rates charged on each of the loans above were lower than what would have been charged under the Company's debt facilities. Fortis Inc. provides Newfoundland Power with an interest discount of 36bps which is equal to the standby fee of 16bps and a direct Fortis discount of 20bps. The interest rate is based on the Bank of Canada rate plus an 80bps stamping fee which is same as the credit facility, minus 16 bps for a standby fee charge which is the unused portion of the credit facility, and a discount of 20 bps.

The Company entered into the following short-term borrowing agreements with related parties during the year:

Loans from Newfoundland Power

Lendee	Maximum Amount Borrowed	Date Borrowed	Date Repaid	Interest Rate [1]
Fortis Inc.	$ 8,000,000	December 8, 2020	On Demand	1.22875%

1. Interest rate will be reset on January 20, 2021.

According to the Company, the interest rate is based on the Bank of Canada rate plus an 120 bps stamping fee which is the same as the credit facility, minus 24 bps for a standby fee charge which is the unused portion of the credit facility, and a discount of 20 bps.

In Order No. P.U. 19 (2003), the Board provided instructions to the Company with respect to the recording and reporting of intercompany transactions. Some of these instructions required reports to be filed with the Board at various times in 2020. Confirmation was received from the Board that quarterly reports relating to intercompany transactions have been filed for 2020.

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 2020 and vouching of a sample of individual transactions to supporting documentation.

(000's)	Actual 2020	Actual 2019	Actual 2018	Variance 2020-2019
Other company fees				
Other company fees	**$ 2,760**	$ 3,746	$ 2,855	$ (986)
Regulatory hearing costs	**184**	312	524	(128)
	$ 2,944	$ 4,058	$ 3,379	$ (1,114)
Year over year percentage change	**(27.5%)**	20.1%	47.2%	(47.60%)
Deferred regulatory costs				
Total deferred regulatory costs	**$ 353**	$ 294	$ 341	$ 59
Year over year percentage change	**20.1%**	(13.8%)	0%	

Other Company Fee costs for 2020 were lower than 2019. According to the Company, this is primarily due to lower consultant costs for customer energy conservation programs.

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 2018 to 2020 is as follows:

(000's)	Actual 2020	Actual 2019	Actual 2018	Variance 2020-2019
Miscellaneous	**$ 1,459**	$ 1,231	$ 994	$ 228
Cafeteria and lunchroom Supplies	**48**	75	77	(27)
Promotional items	**88**	169	137	(81)
Computer Software	**5**	3	10	2
Damage claims	**206**	278	174	(72)
Community relations activities	**1**	1	2	-
Donations and charitable advertising	**132**	195	183	(63)
Books, magazines and subscriptions	**24**	18	7	6
Miscellaneous lease payments	**36**	35	35	1
Total miscellaneous expenses	**$ 1,999**	$ 2,005	$ 1,619	$ (6)
Year over year percentage change	**(0.30%)**	23.84%	(13.84%)	

Miscellaneous expenses by their very nature can fluctuate from year to year. From 2019 to 2020 these expenses have decreased by 0.30% overall but were consistent with the prior year.

Our procedures in this expense category for 2020 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 2020 expenses are unreasonable.

Conservation and Demand Management (CDM)

In compliance with Order No. P.U. 7 (1996-97), the Company filed the 2020 Conservation and Demand Management Report with the Board. This report provided a summary of 2020 CDM activities and costs as well as the outlook for 2021.

In 2015, Newfoundland and Labrador Hydro and Newfoundland Power ("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 2020, the Utilities continued to implement the 2016 Plan while adjusting to COVID-19 related restrictions. These activities include: continuing delivery of the Instant Rebates Program; continuing delivery of the Home Energy Report Program; expanding product rebate categories for the Business Efficiency Program ("BEP"); and establishing new resources to make energy efficiency education more accessible.

CDM costs in 2020 totaled $6,274,000 compared to $7,772,000 in 2019, a $1,498,000 decrease. Conservation costs are lower than in 2019 due to decreased planning costs, Small Technologies Rebate Program costs, and BEP costs.

In 2020, $5,119,000 ($3,583,000 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.

General Expense Capitalized (GEC)

($000's)	Actual 2020	Actual 2019	Actual 2018	Variance 2020-2019
Transfers (GEC)	**(5,175)**	(4,913)	(2,781)	(262)

The capitalization of pension costs has been reflected through the Company's General Expenses Capitalized ("GEC") account based on the GEC methodology approved by the Board in Order No. P.U. 3 (1995-96). In that Order, it was noted that Newfoundland Power was the only utility that included pension costs in a GEC allocation. In the Company's report to the Board, dated August 14, 2020, titled "Review of Capitalization Policies and Guidelines" it was noted by the Company that its practice of capitalizing pension in GEC or capitalized overhead is not common among Canadian utilities. It was also noted in the report that ten of the eleven respondents to a survey capitalize pension costs by means of a labour loader.

In Order No. P.U. 2 (2019), the Board approved the Company's proposal to increase the allocation of pension costs to GEC from 11% to 46%, to comply with Accounting Standards Update 2017-07 – *Improving the Presentation of Net Periodic Pension Costs and Net Periodic Post-Retirement Benefit Cost*, issued in March 2017 by the Financial Accounting Standards Board (the "Update"). This Update provided guidance that the amount of current service pension cost capitalized should reflect the proportion of labour costs that are related to capital work. Utilities that capitalize pension costs using a labour loader would already follow the proportion of labour costs that are related to capital work and therefore would not have been impacted by this Update.

Transfers to GEC for 2020 and 2019 were higher than 2018 due to the increase in the capitalization percentage of current service pension costs as noted above.

Note - The GEC methodology and calculation is currently under review as part of the 2022/2023 General Rate Application filed on May 27, 2021.

Other Operating 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 2020 and 2019.

($000's)	Actual 2020	Actual 2019	Actual 2018	Variance 2020-2019
Vehicle expense	**1,725**	1,681	1,682	44
Operating materials	**1,301**	1,361	1,511	(60)
Inter-company charges	**2,277**	2,058	1,847	219
Plants, Subs, System Oper & Bldgs	**3,484**	3,267	2,812	217
Travel	**638**	1,142	1,127	(504)
Tools and clothing allowance	**1,156**	1,289	1,254	(133)
Conservation	**2,172**	2,813	2,732	(641)
Taxes and assessments	**1,116**	1,156	1,286	(40)
Uncollectible bills	**2,290**	1,980	1,490	310
Insurance	**1,698**	1,397	1,306	301
Severance & other employee costs	**126**	132	68	(6)
Education, training, employee fees	**275**	444	403	(169)
Trustee and directors' fees	**673**	518	481	155
Stationary & copying	**246**	257	224	(11)
Equipment rental/maintenance	**656**	790	784	(134)
Communications	**2,786**	2,803	2,822	(17)
Advertising	**1,264**	1,581	1,443	(317)
Vegetation management	**2,306**	2,042	1,692	264
Computing equipment & software	**2,199**	1,830	1,628	369
Transfers (GEC)	**(5,175)**	(4,913)	(2,781)	(262)
CDM amortization	**5,578**	4,597	3,706	981

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

1. Inter-company charges were higher in 2020 than in 2019 due to higher recoveries charged by Fortis;
2. Plants, substations, system operations and buildings costs for 2020 were higher than 2019 due to increased cleaning costs due to COVID-19, increased snow-clearing costs, and higher generation taxes;
3. Travel costs were lower in 2020 than in 2019 due to companywide restrictions on travel as a result of COVID-19 as well as lower employee relocation costs;
4. Conservation costs were lower in 2020 than in 2019 due to variability in the uptake of customer rebate programs;
5. Uncollectible bills for 2020 were higher than 2019 reflecting a decline in general economic conditions and suspension of service disconnections during the pandemic;
6. Insurance costs for 2020 were higher than in 2019 due to higher premium rates for property insurance;
7. Advertising costs for 2020 were lower than 2019 due to the development of new safety advertising being delayed as a result of COVID-19;
8. Vegetation management costs for 2020 were higher than 2019 due to additional transmission and increased distribution vegetation management activity;
9. Computing Equipment and Software costs were higher in 2020 than in 2019 due to increases in third party software licensing costs; and
10. Amortization of Deferred CDM costs commenced in 2014 and is higher in 2020 due to the inclusion of the seventh year of deferred customer energy conservation programming costs.

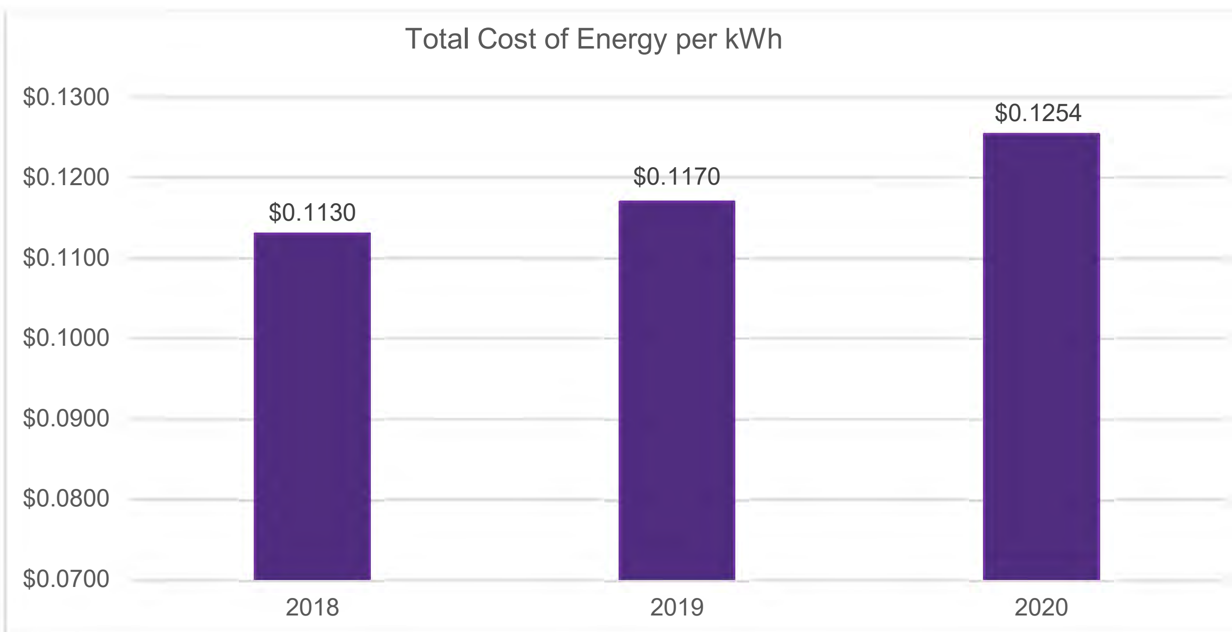
Other Costs

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 2018 to 2020:

000's

Year	kWh sold (000's)	Operating Expenses	Purchased Power	Deferred Cost Recoveries & Amortization	Depreciation	Finance Charges	Income Taxes	Net Earnings	Total Cost of Energy	Cost per kWh
2018	5,876,100	$ 82,588	$ 427,219	$ (1,032)	$ 65,170	$ 36,212	$ 12,280	$ 41,744	$664,181	$ 0.1130
2019	5,846,600	$ 79,209	$ 444,861	$ 1,752	$ 68,019	$ 35,931	$ 11,299	$ 42,891	$683,962	$ 0.1170
2020	5,729,000	$ 86,843	$ 468,844	$ (876)	$ 71,187	$ 37,146	$ 11,893	$ 43,577	$718,614	$ 0.1254



Purchased Power

We have reviewed the Company's purchased power expense for 2020 and have investigated 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 increased by $23.9 million, from $444.9 million in 2019 to $468.8 million in 2020. According to the Company, the costs were higher in 2020 primarily due to an increase in wholesale electricity rates effective October 1, 2019, partially offset by lower energy purchases.

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 2020 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 2020; and,
- assessed the overall reasonableness of the depreciation for 2020.

Amortization expense for 2020 is $71,187,000 as compared to $68,019,000 for 2019, representing a 4.7% increase. The 2020 and 2019 depreciation expense exclude 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)	**2020**	**2019**	**Variance 2020-2019**	**%**
Depreciation and amortization as reported	**$71,187**	$68,019	$3,168	4.7%
Less: Tax on Cost of Removal *(1)*	**(6,205)**	(5,953)	(252)	4.2%
Depreciation of Fixed Assets	**$64,982**	$62,066	$2,916	4.7%

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

Depreciation of fixed assets for 2020 is $64,982,000 as compared to $62,066,000 for 2019, representing a 4.7% increase. The change is attributable to an increase of depreciable assets by approximately $65,861,000. The following table provides a comparison of the depreciation of fixed assets for 2020, 2019, and 2018:

(000's)	2020	2019	2018	Variance 2020-2019	Variance 2019-2018
Depreciation of Fixed Assets	**$64,982**	$62,066	$59,466	$2,916	$2,600

Note – A new depreciation study, based on the Company's electric plant as of December 31, 2019, is currently under review as part of the 2022/2023 General Rate Application filed on May 27, 2021.

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), Order No. P.U. 18 (2016), and Order No. P.U. 2 (2019). 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 2020.

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 results of our procedures have been outlined below.

The following table summarizes the various components of finance charges expense for the years 2018 to 2020:

(000's)	Actual 2020	Actual 2019	Actual 2018	Variance 2020-2019
Interest				
Long-term debt	**$ 36,811**	$ 35,375	$ 35,788	$ 1,436
Other	**624**	1,384	712	(760)
Amortization				
Debt discount	**233**	235	235	(2)
Interest charged to construction	**(522)**	(1,063)	(523)	541
Total Finance charges	**$ 37,146**	$ 35,931	$ 36,212	$ 1,215
Year over year percentage change	**3.38%**	(0.78%)	2.40%	

The following observations were made with respect to the more significant fluctuations in finance charges:

- The increase in long-term debt interest was due to the bond issuance of Series AQ for $100 million in Q2 of 2020.
- Other interest was lower due to less short-term borrowings primarily to the Series AQ bond issuance of $100 million in Q2 of 2020.
- Interest charged to construction was higher in 2019 due to two larger capital projects completed in that year, namely the purchase of a new gas turbine and the Human Resources Information System (HRIS).

Based upon our analysis, nothing has come to our attention to indicate that the finance charges for 2020 are unreasonable.

Income Tax Expense

We have reviewed the Company's income tax expense for 2020 and have noted that the effective income tax rate increased from 20.9% in 2019 to 21.4% in 2020. Actual income tax expense in 2020 and 2019 results in the following effective rates:

	2020	2019	2018	2020-2019
Income tax expense	**$ 11,893**	$ 11,299	$ 12,280	$ 594
Earnings before income tax	**$ 55,470**	$ 54,190	$ 54,024	$ 1,280
Effective income tax rate	**21.4%**	20.9%	22.7%	0.5%

Income tax expense increased by $594,000 compared to 2019. The statutory tax rate was 30.0% for both 2020 and 2019.

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 2020 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 $384,831 for the current period compare to a total of $365,056 for the same period during the previous year. According to the Company, the credit total for the 2019-2020 winter season is higher than the previous season total primarily due to higher customer participation and a lower number of customer curtailment failures. There were 24 option participants in 2019-2020, 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 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 2020 to prior years and investigated any significant fluctuations;
- reviewed detailed listings of expenses for 2020 and investigated any significant 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 2020	Actual 2019	Actual 2018	Variance 2020-2019
Charged from Fortis Companies	**$ 2,251,000**	$ 2,115,024	$ 1,904,428	$ 135,976
Performance and restricted share units	**1,083,018**	665,058	346,789	417,960
Donations and charitable advertising	**210,426**	336,662	295,769	(126,236)
Executive short-term incentive	**576,510**	419,479	514,004	157,031
Miscellaneous	**10,934**	40,265	61,088	(29,331)
	4,131,888	3,576,488	3,122,078	555,400
Less: Income Taxes	**1,239,566**	1,072,946	936,623	166,620
Total non-regulated (net of tax)	**$ 2,892,322**	$ 2,503,542	$ 2,185,455	$ 388,780

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 measure. For 2020, this represents an addition to non-regulated expenses (before tax adjustment) of $576,510 (2019 - $419,479). However, it should be noted that these Orders were issued prior to the replacement of the regulatory performance measure with the cash flow performance measure in 2019; the cash flow measure is included in regulated expense at 100% of target. 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 2020 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 2019 and 2020:

(000's)	2020 Actual	2019 Actual	Variance 2020-2019
Regulatory Assets			
OPEBs asset (ii)	$ 17,520	$ 21,024	$ (3,504)
Deferred GRA costs (iii)	353	706	(353)
Conservation and demand management deferral (iv)	24,356	24,815	(459)
Demand management incentive (v)	1,431	2,687	(1,256)
Employee future benefits (vi)	74,752	86,366	(11,614)
Weather normalization account (vii)	-	8,078	(8,078)
Deferred income taxes (viii)	227,450	220,232	7,218
	$ 345,862	$ 363,908	$ (18,046)
Regulatory Liabilities			
Rate stabilization account (i)	$ 22,035	$ 16,107	$ 5,928
Cost recovery deferral (ix)	876	1,752	(876)
Weather normalization account (vii)	5,333	-	5,333
Future removal and site restoration provision (x)	178,469	168,740	9,729
	$ 206,713	$ 186,599	$ 20,114

(i) Rate Stabilization Account

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. On June 17, 2020, Order P.U. 16 (2020), the PUB approved a wholesale bill credit of approximately $50.6 million. In Order No. P.U. 17 (2020), the Board approved the one-time bill credit of approximately $47.7 million to eligible customers. This resulted in no change to customer electricity rates effective July 1, 2020. In Order No. P.U. 17 (2020) the Board also approved the balance owed to customers with respect to the operation of the Company's RSA for 2020 for $2,753,500.

As of December 31, 2020, there was a refund to customers transferred to the RSA of $21,440,309 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 a transfer of $321,225 to the RSA for undistributed credits to customers related to the July 2020 one time customer bill credit approved by the Board in Order No. P.U. 17 (2020).

Pursuant to Order No. P.U. 31 (2010), the Board approved the Company's proposal to create the 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 31st in the year in which the difference arises. As of March 31, 2020, the credit balance of $261,740 in the OPEBVDA account was transferred to the RSA, as approved in Order No. P.U. 16 (2013).

Pursuant to Order No. P.U. 43 (2009), the Board approved the Company's proposal to create a 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, 2020, the balance of $6,556,521 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 RSA. As of March 31, 2020, $8,077,818 and $5,577,693 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 for $2,686,951 as approved in Order No. P.U. 11 (2020).

Pursuant to Order No. P.U. 2 (2019), the Board approve the Company's proposed disposition of the 2020 Revenue Requirement Shortfall. As of March 31, 2020, the balance of $258,000 in the Revenue Requirement Shortfall account was credited to the RSA.

(ii) Other Post-Employment Benefits

The 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 $52.6 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).

(iii) Deferred general rate application costs

In Order No. P.U. 2 (2019), the Board approved the deferral of cost related to 2019/2020 GRA as well as amortization of this deferral over a 34-month period commencing on March 1, 2019 and ending December 31, 2021. Actual costs incurred and deferred were approximately $1,000,000 with amortization of $353,000 incurred in 2020.

(iv) 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 RSA. The actual costs incurred and deferred at December 31, 2020 were $24,356,000 with amortization of $5,577,693 in 2020.

(v) Demand Management Incentive

In Order No. P.U. 32 (2007), the Board approved the Company's proposal to create the Demand Management Incentive Account to replace the Purchased Power Unit Cost Variance Reserve. This account aims to isolate the demand costs and is equal to plus or minus 1% of test year wholesale demand charges. The Demand Management Incentive as at December 31, 2020 was $1,431,000 ($1,002,000 after tax).

(vi) 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:

- 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,
- 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, 2020, the regulated asset for employee future benefits was $74,752,000.

(vii) 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 RSA at March 31st of the following year. In Order No. P.U. 13 (2021), the Board approved the December 31, 2020 net regulatory liability balance in the Weather Normalization Account of $5,333,000 ($3,734,000 net of deferred income tax).

(viii) 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, 2020 was $227,450,000.

(ix) Cost Recovery Deferral

In 2019, there was an over-recovery of revenue due to a March 1, 2019 rate implementation date. In Order No. P.U. 2 (2019), the Board approved amortization over a 34-month period from March 1, 2019 to December 31, 2021 to provide recovery in customer rates of any 2019 revenue shortfall/over-recovery associated with the March 1, 2019 rate implementation. The over-recovery of revenue was approximately $2,482,000 with accumulated amortization of

$1,606,000. The net regulating liability for deferred costs – 2019 Cost Recovery Deferral at December 31, 2020 was approximately $876,000.

(x) 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 2020, the balance in this account was $178,469,000 (2019 - $168,740,000).

Based upon our analysis, nothing has come to our attention to indicate that changes in regulatory deferrals for 2020 are unreasonable.

Pension Expense Variance Deferral Account

Scope: ***Review of calculation of the Pension Expense Variance Deferral Account 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 RSA as of the 31st day of March in the year in which the difference arises.

The 2020 PEVDA was calculated at $6,556,521. This balance was transferred to the RSA as a charge on March 31, 2020 in accordance with Order No. P.U. 43 (2009).

We confirm that the 2020 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 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 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 RSA as of the 31st day of March in the year in which the difference arises.

The 2020 OPEBVDA was calculated at $261,740. This balance was transferred to the RSA as a charge on March 31, 2020 in accordance with Order No. P.U. 31 (2010).

We confirm that the 2020 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 2020 are as follows:

1. Made capital investments of $89 million of which over 62% 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 of the distribution system along with improving the ability to locate and isolate system trouble.

6. The Company revised and improved how it monitors and manages safety. The monthly safety management performance report was replaced with online dashboards from the new safety management software, Intelex. Safety performance is now managed in real time.

7. Newfoundland Power made adjustments to its operations to protect the safety of its employees and customers due to the COVID-19 pandemic. Newfoundland Power continued delivering safe, reliable electricity while remaining focused on the health and safety of employees, customers, and communities. The Company responded swiftly, providing customers with bill assistance by suspending collections and disconnections, offering flexible payment arrangements, and encouraging customers to avail of our online convenience options such as myAccount, ebills, and equal payment plans. Safe work procedures were developed to ensure work is completed safely when physical distancing cannot be maintained.

8. Deployed additional laptop computers and software to allow staff to effectively and efficiently work from home during the pandemic.

9. TakeCHARGE launched electric vehicle ("EV") educational resources at TakeChargeNL.ca/EVs with the help of $50,000 in funding from Natural Resources Canada. The enhancements provide customers with information and tools to help them determine if an EV is right for their lifestyle. The website also contains a carbon reduction calculator so customers can see the positive environmental impact of switching from an internal combustion engine vehicle to an EV. The website is a major milestone in the Company's electrification efforts, providing the foundation for future growth of electric vehicles in the province.

10. Newfoundland Power started its climate adaptation planning by collaborating and sharing resource information with FortisAlberta and FortisBC who are also in a similar stage of planning. The initial focus is on how our geographic information system ("GIS") can be leveraged to track climate risk for the organization. A gap analysis was completed to verify its alignment with the national criteria established through the Canadian Electricity Association's Sustainable Electricity Brand.

11. As a step toward adoption of the CEA Sustainable Electricity Company designation, Newfoundland Power contracted CanSustain to support a review of the ISO 26000 core subjects and issues, to determine which are most significant to Newfoundland Power's operations. This sustainability standard addresses a broad range of environmental, social and governance indicators.

12. In response to the pandemic the government provided up to $2.5 million to waive interest on eligible overdue electricity bills. Approximately 38,000 eligible residential accounts were enrolled automatically, and 118 general service customers were enrolled upon request.

13. TakeCHARGE received two ENERGY STAR® awards. Newfoundland Power was recognized with "Promotional Campaign of the Year" and "Utility Program of the Year" for the promotion of ENERGY STAR certified products in the marketplace, including the delivery of the Instant Rebates program.

14. The Company launched its new Human Resource Management System ("V.I.P."). This new system replaces a 20-year old software application that was no longer supported by the vendor. V.I.P. brings support, stability, and new functionality. Previously two separate systems were needed for human resource and payroll functions. V.I.P. now houses both.

15. The Company launched its commitment to inclusion and diversity (I & D) to ensure employees are working in a supportive, inclusive and diverse workplace. Following a call for volunteers, 12 employees were selected for the inaugural Champions Network - a working group to support and influence I & D initiatives and foster an inclusive culture through events, training, best practices, policies, and workplace culture documents.

16. The Company completed a reassessment of its Cybersecurity Risk Management Program ("CRMP") in both Information Technology ("IT") and Operations Technology ("OT") environments. The re-assessment showed reduction in risk for the IT and OT environments, mostly due to improved documentation of existing controls.

17. A number of cybersecurity improvements were completed. These included implementation of a Privileged Access Management ("PAM") system, enabling better control and efficiency in managing administrative accounts and security privileges and a core network upgrade including new internal network firewalls, providing increased visibility on network traffic and better monitoring of cyber threats.

18. A new Electrification, Conservation and Demand Management Plan (2021-2025) was filed with the Board. This plan includes longstanding customer CDM programs and supporting initiatives and also introduces customer electrification programs for the first time. These programs will lower overall costs for participating customers and provide rate mitigating benefits over the long term. The Electrification, Conservation and Demand Management Plan remains under review with the Board.

19. Self-service functions were added to the Company's website to help customers with the Equal Payment Plan. New features allow customers to view personal energy consumption and account balances and make quarterly changes to payment amounts.

20. Customers now have the ability to sign-up for Automatic Payment Plan electronically and securely, replacing the paper form previously required. Customers can avail of this option through their myAccount portal on Newfoundland Power's website. A video training platform was introduced providing benefit to the regional operations and engineering groups.

21. An existing technology deployed at Newfoundland Power, called Workplace, was expanded to provide a platform to store, maintain and view refresher training and instructional or informational videos developed by employees.

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 by the Company:

Category	Measure	Actual 2018	Actual 2019	Actual 2020	Plan 2020	Measure Achieved
Reliability	Outage Hours/Customer (SAIDI) – excluding Hydro loss of supply[1]	2.65	2.34	2.98	2.37	No
	Outage/Customer (SAIFI) – excluding Hydro loss of supply[1]	1.67	1.62	2.35	1.64	No
	Plant Availability (%)[2]	96.3	95.7	96.8	95.0	Yes
Customer Satisfaction	% of Satisfied Customers as measured by Customer Satisfaction Survey	85.6	85.8	87.6	85.8	Yes
	Call Centre Service Level (% per second)[3]	81/60	77/60	81/60	80/60	Yes
	Trouble Call Responded to Within 2 Hours (%)	85.0	81.0	80.0	85.0	No
Safety	All Injury/Illness Frequency Rate	0.9	0.4	0.7	0.7	Yes
Financial	Earnings (millions)[4]	$41.2	$42.3	$43.2	$42.1	Yes
	Gross Operating Cost/Customer[5]	$225	$229	$235	$238	Yes

[1] 2018 statistics exclude the impact of wind storms in April & November and a Power Transformer failure in November. 2019 statistics exclude the impact of a wind storm in February, Hurricane Dorian in September and a snow storm in November. 2020 statistics excludes the impact for the snow storm in January.
[2] Excludes the hours of generation unit is out of service due to system disruptions and major plant refurbishment.
[3] Service level is based on calls answered in 60 seconds.
[4] Earnings applicable to common shares.
[5] Excluding conservation program costs, pension, OPEBs and early retirement program costs.

The following table compares whether the Company measures were achieved during the 2018, 2019, and 2020 years:

Category	Measure	Measure Achieved 2018	Measure Achieved 2019	Measure Achieved 2020
Reliability	Outage Hours/Customer (SAIDI) – excluding Hydro loss of supply	No	Yes	No
	Outage/Customer (SAIFI) – excluding Hydro loss of supply	Yes	Yes	No
	Plant Availability (%)	Yes	Yes	Yes
Customer Satisfaction	% of Satisfied Customers as measured by Customer Satisfaction Survey	No	Yes	Yes
	Call Centre Service Level (% per second)	Yes	No	Yes
	Trouble Call Responded to Within 2 Hours (%)	Yes	No	No
Safety	All Injury/Illness Frequency Rate	No	Yes	Yes
Financial	Earnings (millions)	Yes	Yes	Yes
	Gross Operating Cost/Customer	No	Yes	Yes

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Grant Thornton
2021 Annual Financial Review of Newfoundland Power Inc.

Board of Commissioners of Public Utilities

Financial Consultants Report
2021 Annual Financial Review of
Newfoundland Power Inc.

Table of Contents

Restrictions, Qualifications and Independence

Purpose

This report was prepared for the Board of Commissioners of Public Utilities ("the Board") in Newfoundland and Labrador. The purpose of our engagement was to present our observations, findings and recommendations with respect to our 2021 annual financial review of Newfoundland Power Inc. ("the Company") ("Newfoundland Power").

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 and will also be available on the Board's website. We have given the Board our consent to use our report for these purposes.

This report shall be solely for the benefit of the Board and not for the benefit of any third party and may be relied upon only for the purpose for which the report is intended as contemplated and/or defined within the engagement. Grant Thornton recognizes no responsibility whatsoever, other than that owed to the Board as at the date on which the report is given to the Board by Grant Thornton, for any unauthorized use of or reliance on the report.

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 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 presents our observations and findings with respect to our 2021 Annual Financial Review of Newfoundland Power. Below is a summary of the key observations and findings included in our report.

- The average rate base for 2021 was $1,202,946,000 which is an increase of $21,049,000 (1.75%) over the average rate base for 2020 of $1,181,897,000. The Company's calculation of the return on average rate base for 2021 was 6.74% (2020 – 7.04%) compared to an approved rate of return of 6.65%. The actual rate of return was within the range approved by the Board (6.47% to 6.83%). 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 2021 was $521,048,000 (2020 - $516,759,000). The Company's actual return on average common equity for the year ended December 31, 2021 was 8.88% (2020 – 8.93%). In Order No. P.U. 32 (2007), the Board ordered that if 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, the Company must file a report with its annual return explaining the facts and circumstances contributing to the difference. In 2021 the approved cost of common equity was 8.50% as per Order No. P.U. 36 (2020). The actual return on average common equity for 2021 was 8.88% as noted above. This return was within the 50-basis point limit and as such no report was required.

- Total actual capital expenditures (excluding capital projects carried forward from prior years) were 12.58% under budget in 2021. Total capital expenditures (including projects carried over from prior years) were over the approved budget on a net basis by $1,721,000 (1.09%). However, for each category of expenditure, the variances ranged from an over-budget of 8.02% to an under-budget of 100.00%.

- The Company experienced a 0.32% decrease in revenue from rates in 2021 as compared to 2020. The decrease is primarily due to lower electricity sales from residential customers.

- Overall, net operating expenses increased by $1,307,000 from 2020 to 2021. Significant operating expense variances are discussed throughout our report. We conducted an examination of other costs including, depreciation, interest and income taxes and have noted that nothing has come to our attention to indicate that these costs for 2021 are unreasonable.

- During our review of non-regulated expenses, nothing came 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.

- The 2021 Pension Expense Variance Deferral Account ("PEVDA") operated in accordance with Order No. P.U. 43 (2009).

- The 2021 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 2021 the Company met eight out of nine of its planned performance measures. The Company fell short of its targets in "Outage Hours/Customer (SAIDI)", as discussed later in this report.

Introduction

This report to the Board presents our observations and findings with respect to our 2021 Annual Financial Review of Newfoundland Power.

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

4. Review intercompany charges and assess compliance with Board Orders including requirements for additional reports pursuant to Order No. P.U. 19 (2003), Order No. P.U. 32 (2007), Order No. P.U. 43 (2009), and Order No. P.U. 13 (2013).

5. Examine the Company's 2021 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 2014 Depreciation Study and review the calculations of depreciation expense.

7. Review Minutes of Board of Directors' meetings.

8. Review the Company's initiatives 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 based on the nature 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 financial statements of the Company for the year ended December 31, 2021 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 10, 2022. 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

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

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 31, 2022, the Company filed its 2021 Annual Report to the Board. The Company noted in the report that there are no significant changes to the system of accounts, only minor wording changes were made to improve the clarity and accuracy of the account descriptions.

Based upon our review of the Company's financial records we have found that they are in compliance with the system of accounts approved 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, 2021 which is included on Return 3 of the annual report to the Board was calculated using the Asset Rate Base Method ("ARBM"). The average rate base for 2021 was $1,202,946,000 which is an increase of $21,049,000 (1.75%) over the average rate base for 2020 of $1,181,897,000. 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 2021; 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 2020 and 2021 (all figures shown are averages):

(000)'s	2021	2020
Net Plant Investment (average)		
Plant Investment	$ 2,062,375	$ 1,987,608
Accumulated Depreciation	(848,714)	(809,124)
CIAC's	(44,569)	(44,487)
	1,169,092	1,133,997
Additions to Rate Base (average)		
Deferred Charges (a)	89,465	90,916
Cost Recovery Deferral for Hearing Costs (b)	124	371
Cost Recovery Deferral – Conservation (c)	16,735	17,210
Customer Finance Programs (d)	1,927	2,296
Demand Management Incentive Account (e)	1,172	1,442
Weather Normalization Reserve (f)	-	960
	109,423	113,195
Deductions from Rate Base (average)		
Weather Normalization Reserve (f)	2,877	-
Other Post-Employment Benefits (g)	70,153	64,265
Customer Security Deposits (h)	1,307	1,316
Accrued Pension Obligation (i)	5,213	5,181
Deferred Income Taxes (j)	14,330	11,386
Cost Recovery Deferral – 2016 Cost Recovery Deferral (k)	307	920
	94,187	83,067
Average Rate Base before Allowances	1,184,330	1,164,125
Rate Base Allowances		
Materials and Supplies	8,339	7,270
Cash Working Capital	10,277	10,503
	18,616	17,773
Average Rate Base	$ 1,202,946	$ 1,181,897

(a) The Company's rate base is determined using the ARBM which incorporates average deferred charges into the calculation of rate base. The total average deferred charges of $89,465,000 (2020 - $90,916,000) included in the 2021 rate base consists of average deferred pension costs of $89,394,000 (2020 - $90,862,000) and credit facility costs of $71,000 (2020- $54,000). The Company has included a schedule of these costs in Return 8.

(b) In Order No. P.U. 2 (2019), the Board approved the 34-month amortization of $1,000,000 in estimated hearing costs related to the 2019/2020 General Rate Application, commencing March 1, 2019 through December 31, 2021. According to the Company, the actual hearing costs for the 2019/2020 General Rate Application were $329,728. The Company transferred $670,272 to the Rate Stabilization Account on March 31, 2019 representing the difference between actual of $329,728 and estimated costs of $1,000,000 as directed by the Board in Order No. P.U. 2 (2019) instead of a reduction in rate base in 2019. The 2021 average rate base includes an addition of $124,000 (average of $247,000 and $Nil for 2020 and 2021 relating to these hearing costs).

(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.

In Order No. P.U. 3 (2022), the Board approved the amortization of annual costs over 10 years, commencing January 1, 2021 for historical balances and annual charges. The implementation of Order No. P.U. 3 (2022) resulted in a $1,875,000 true-up increase in deferred conservation costs in 2022 relating to annual deferred customer energy conservation program costs incurred up to December 31, 2021.

In 2021, the actual costs incurred and deferred were $4,991,000 ($3,494,000 after tax) and the amortization will be $499,000 beginning in 2022; the 2021 deferred conservation balance would not include the implementation of the change in amortization to 10 years as the amortization is booked the year after incurred. Included in the calculation of the average rate base for 2021 is $16,735,000 (2020 - $17,210,000) 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 2021 average rate base incorporates $1,926,000 (2020 - $2,296,000) related to these programs.

(e) In Order No. P.U. 14 (2021), the Board approved the disposition of the 2020 balance of the Demand Incentive Account of $1,431,000 ($1,002,000 after tax) by means of a debit to the Rate Stabilization Account as of March 31, 2021. In Order No. P.U. 10 (2022), the Board approved the disposition of the 2021 balance of the Demand Incentive Account of $1,917,000 ($1,342,000 after tax) by means of a debit to the Rate Stabilization Account as of March 31, 2022. The 2021 average rate base incorporates $1,172,000 (2020 - $1,442,000) related to this account.

(f) During 2021, 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 decrease to the reserve of $3,734,000 in 2021 (2020 – $5,654,000 increase).

Other transfers:

i. $10,366,000 increase to the reserve related to the after-tax impact of the Degree Day Normalization Reserve Transfer (2020 – $3,856,000 increase).
ii. $8,346,000 decrease to the reserve related to the after tax impact of the Hydro Production Equalization Reserve transfer (2020 - $122,000 decrease).

The net impact was a net increase to the reserve of $1,714,000 (2020 - $9,388,000 decrease). The ending balance in this reserve account totaled $2,020,000 compared to a balance of 3,734,000 at December 31, 2020 (an average of ($2,877,000) for 2021) (2020 – ($960,000)). This represents a balance owed to customers.

(g) Other Post-Employment Benefits is equal to the difference, at December 31, 2021, between the OPEBs liability of $88,675,000 and the OPEBs asset of $15,109,000. The calculation of the 2021 average rate base of $70,152,000 is equal to the average of the December 31, 2021 net liability of $73,566,000 and the December 31, 2020 net liability of $66,739,000.

(h) Customer Security Deposits are comprised of security deposits received from customers for electrical services as outlined with the Board approved Schedule of Rates, Rules and Regulations. The calculation of the 2021 average rate base incorporates $1,306,000 (2020 - $1,316,000) related to customer security deposits.

(i) The 2021 average rate base calculation incorporates $5,213,000 (2020 - $5,182,000) 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 2021 average rate base is ($3,401,000) and ($18,129,000) respectively. The remaining balance of the deferred income tax liability in the amount of $35,860,000 relates to capital assets. This results in an average balance for deferred income tax liability of $14,330,000 (2020 - $11,386,000).

(k) In Order No. P.U. 2 (2019), the Board approved the deferral over a 34-month period of a $2,482,000 (before tax) revenue surplus from March 1, 2019 rate implementation of rates. The 2021 average rate base includes a deduction of $307,000 (2020 - $920,000).

The net change in the Company's average rate base from 2020 to 2021 can be summarized as follows:

(000's)	2021	2020
Average rate base - opening balance	$ 1,181,897	$ 1,153,556
Change in average deferred charges and deferred regulatory costs	(1,560)	471
Average change in:		
Plant in service	74,767	78,115
Accumulated depreciation	(39,590)	(37,536)
Contributions in aid of construction	(82)	(2,891)
Weather normalization reserve	(3,837)	(2,626)
Other post-employment benefits	(5,887)	(4,814)
Future income taxes	(2,944)	(3,898)
Rate base allowances	843	1,391
Customer Finance Programs	(369)	(181)
Demand Management Incentive Acct	(269)	501
Other rate base components (net)	(23)	(191)
Average rate base - ending balance	$ 1,202,946	$ 1,181,897

Based upon the results of the above procedures we did not note any discrepancies in the calculation of the 2021 average rate base, and therefore conclude that the 2021 average rate base included in the Company's annual report to the Board is 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 2021 was 6.74% (2020 – 7.04%). 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. The return on average rate base is calculated in accordance with the methodology approved in Order No. P.U. 32 (2007).

The actual return on average rate base in comparison to the range of allowed return for each of the years from 2019 to 2021 is set out in the table below.

	2021	2020	2019
Actual Return on Average Rate Base	**6.74%**	7.04%	6.97%
Upper End of Range set by the Board	**6.83%**	7.22%	7.19%
Lower End of Range set by the Board	**6.47%**	6.86%	6.83%

The Board approved the Company's rate of return on average rate base of 6.65% in a range of 6.47% to 6.83% for 2021 in Order No. P.U. 36 (2020). As noted above, the Company's actual return on average rate base for 2021 was 6.74% which was inside 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. 2 (2019), the Board reconfirmed its previous position as per Order No. P.U. 13 (2013) regarding the capital structure for Newfoundland Power 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 2021 as reported in Return 24 is as follows:

	2021 Average		2020	2019
	(000's)	Percent	Percent	Percent
Debt	$ 638,598	55.07%	54.70%	54.28%
Preferred equity (1)	-	0.00%	0.39%	0.78%
Common equity	521,048	44.93%	44.91%	44.94%
	$ 1,159,646	100%	100%	100%

Note 1 – The Company's preferred shares were redeemed in 2020.

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 2021 in Return 26. The embedded cost of debt for 2021 was 5.61% which represents a 37 bps decrease from the 2020 embedded cost of debt of 5.98%.

Based on the information indicated above, we conclude that the capital structure included in the Company's annual report to the Board is in accordance with Order No. P.U. 2 (2019).

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, 2021 is included on Return 27 of the annual report to the Board. The average common equity for 2021 was $521,048,000 (2020 - $516,759,000). The Company's actual return on average common equity for 2021 was 8.88% (2020 – 8.93%).

Our procedures 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 common equity per Order No. P.U. 40 (2005), including the deemed capital structure per Order Nos. P.U. 19 (2003), P.U. 32 (2007), P.U. 43(2009), P.U. 13 (2013), P.U. 18 (2016), and P.U. 2 (2019); and,
- recalculated the rate of return on common equity for 2021 and ensured it was in accordance with Order Nos. P.U. 32 (2007) and P.U. 36 (2020).

In Order No. P.U. 32 (2007), the Board ordered that where in a given year the actual rate of ROE is greater than 50 bps above the test year calculation of the cost of equity for the same year, the Company must file a report with its annual return explaining the facts and circumstances contributing to the difference. Per Order No. P.U. 2 (2019) the approved cost of common equity for 2021 was 8.50%. The actual return on average common equity for 2021 was 8.88%. Therefore, the actual return on average common equity was within the 50-basis point limit and no additional reporting 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)	2021	2020	2019
Net Income	**$ 43,757**	$ 43,577	$ 42,892
Income Taxes	**11,603**	11,893	11,298
Interest on long term debt	**35,450**	36,811	35,375
Interest during construction	**(995)**	(949)	(1,933)
Other interest and amortization of discount costs	**400**	842	1,590
Total	**$ 90,215**	$ 92,174	$ 89,222
Interest on long term debt	**$ 35,450**	$ 36,811	$ 35,375
Other interest and amortization of discount costs	**400**	842	1,590
Total	**$ 35,850**	$ 37,653	$ 36,965
Interest Coverage (times)	**2.5**	2.4	2.4

The above table shows that the interest was consistent from 2018 to 2020 with a slight increase in 2021.

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 2021 is 2.5 times.

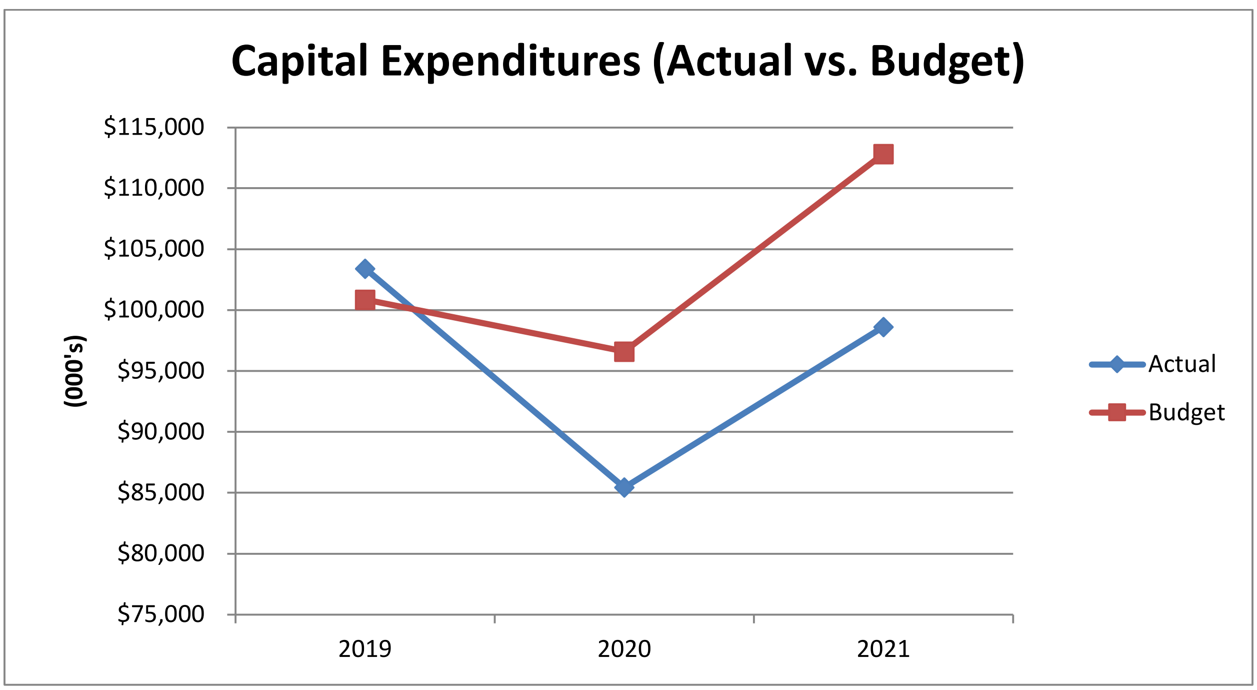
Capital Expenditures

Scope: ***Review the Company's 2021 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 2019 to 2021:

($000's)	2019	2020	2021	Notes
Actual	$ 103,417	$ 85,447	**$ 98,640**	1
Budget	$ 100,856	$ 96,614	**$ 112,836**	
Over (under) budget	2.54%	(11.56%)	**(12.58%)**	

Note 1: Total expenditures per the 2021 Capital Budget report includes the carryover amount of $17,285,000 for a total of $115,925,000. The carryover amount is made up of eight projects included in the following categories; $300,000 to Generation; $2,547,000 to Substation; $1,237,000 to Transmission; $2,950,000 to Distribution, $351,000 to General property, $2,415,000 to Transportation, $112,000 to Telecommunication, and $7,373,000 to Information Systems. According to the Company, these expenditures will occur in 2022.



The following table provides a summary of the capital expenditure activity in 2021 as reported in the Company's *"2021 Capital Expenditure Report":*

($000's)	Capital Budget			Actual Expenditures		
	Prior Years	2021	Total	Prior Years	2021	Total
2021 Capital Projects (1)	$ -	$ 112,836	$ 112,836	$ -	$ 98,640	$ 98,640
2020 Projects Carried to 2021 & Multi Year Projects						
Transmission line rebuild	9,623	-	9,623	8,002	2,067	10,069
Application enhancement	1,428	-	1,428	1,346	206	1,552
Systen Upgrades	2,592	-	2,592	2,422	402	2,824
Company Building Renovations	1,172	-	1,172	1,116	76	1,192
Purchase Vehicles and Aerial Devices	3,869	-	3,869	2,254	1,261	3,515
Purchase Mobile Generation	13,915	-	13,915	13,257	102	13,359
Topsail Hydro Plant Refurbishment	485	-	485	319	170	489
Petty Harbour Hydro Plant Refurbished	3,662	-	3,662	337	3,162	3,499
Rattling Brook Plant Refurbishment	1,183	-	1,183	100	785	885
Hydro Facility Rehabiliation	1,519	-	1,519	1,368	50	1,418
Substation Feeder Termination	290	-	290	76	203	279
Trunk Feeders	2,820	-	2,820	707	1,560	2,267
Feeder Additions for Load Growth	2,302	-	2,302	1,718	426	2,144
	44,860	-	44,860	33,022	10,470	43,492
Grand Total	**$ 44,860**	**$ 112,836**	**$ 157,696**	**$ 33,022**	**$109,110**	**$ 142,132**

Note 1 - Approved in Order Nos. P.U. 37 (2020), P.U. 12 (2021) and P.U. 30 (2021).

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

($000's)	2021 Budget (1)	2021 Actuals (2)	Variance	Carryover (3)	Variance Including Carryover	%
Generation - Hydro	**18,029**	**15,548**	(2,481)	300	(2,181)	(12.10%)
Generation - Thermal	**14,245**	**13,659**	(586)	-	(586)	(4.11%)
Substation	**14,570**	**13,191**	(1,379)	2,547	1,168	8.02%
Transmission	**19,374**	**19,227**	(147)	1,237	1,090	5.63%
Distribution	**52,535**	**52,227**	(308)	2,950	2,642	5.03%
General property	**3,948**	**3,512**	(436)	351	(85)	(2.15%)
Transportation	**7,901**	**5,198**	(2,703)	2,415	(288)	(3.65%)
Telecommunications	**462**	**312**	(150)	112	(38)	(8.23%)
Information systems	**19,382**	**12,463**	(6,919)	7,373	454	2.34%
Unforeseen	**750**	**-**	(750)	-	(750)	(100.00%)
General expenses capitalized	**6,500**	**6,795**	295	-	295	4.54%
Total	**$ 157,696**	**$ 142,132**	**($15,564)**	**$ 17,285**	**$ 1,721**	**1.09%**

Note 1 - Includes prior years projects and current year budgeted amounts as there were projects incomplete at the previous year ends.
Note 2 - 2021 actuals include the total expense for projects carried forward from 2020.
Note 3 - Represents $17,285,000 in capital projects carried forward to 2022.

As indicated in the table, actual capital expenditures were less than the approved budget by $15,564,000 and when carryover amounts are considered, they were $1,721,000 (1.09%) higher. However, for each category of expenditure, the variances ranged from an over-budget of 8.02% for the substation category to an under-budget of 100.00% 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)
Additions Due to Load Growth	2,547
Transmission Line Extension - 35L	1,237
Trunk Feeders	792
Feeder Additions for Load Growth	671
Utility EV Charging Network	1,487
Company Building Renovations	351
Purchase Vehicles and Aerial Devices	2,415
Fibre Optic Cable Builds	112
Application Enhancements	186
Network Infrastructure	94
Topsail Hydro Plant Refurbishment	300
Customer Service System Replacement	7,093
Total Carryover	**$ 17,285**

The Company has provided detailed explanations on budget to actual variances in Appendix A of its "2021 Capital Expenditure Report".

Adherence to Capital Budget Application Guidelines

Based on our review, the Company's 2021 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% off the approved budget.

- 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 2.54% in 2019, (11.56%) in 2020 and (12.58%) in 2021. When taking into consideration carryovers, the variance was 5.21% in 2019, 0.63% in 2020 and 1.09% in 2021 resulting in no additional reporting requirements.

The allowance for unforeseen items account was not utilized in 2021.

<u>Capital Expenditure Reports</u>

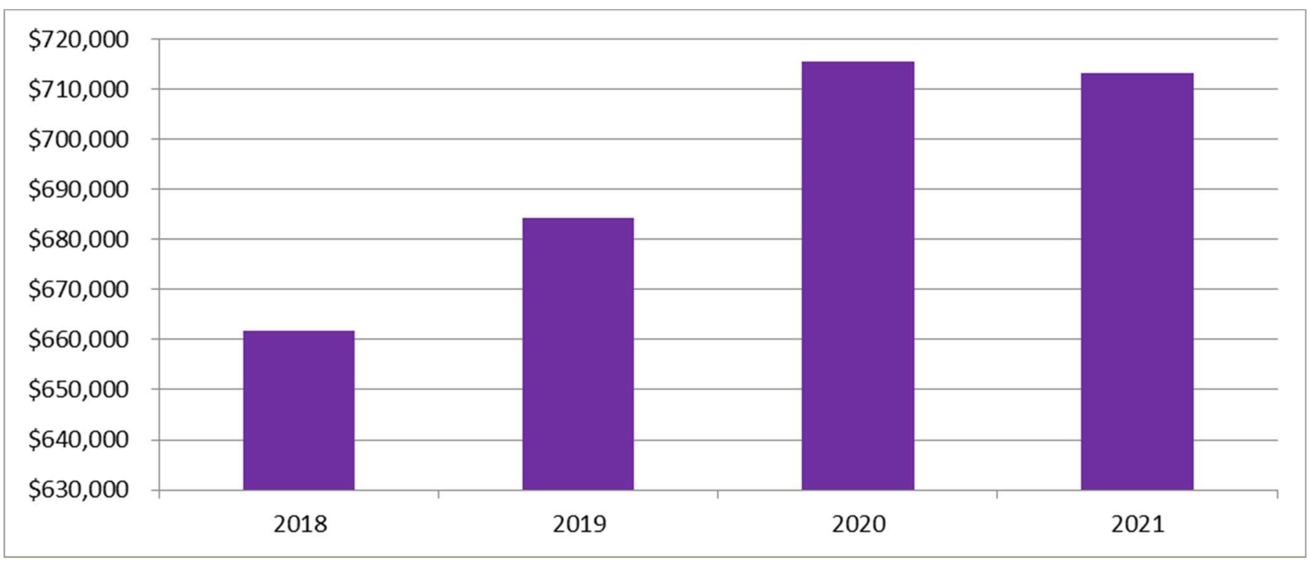
The Company filed quarterly Capital Expenditure reports for the 2021 calendar year on time.

Revenue from rates

Scope: ***Review the Company's 2021 revenue from rates in comparison to prior years and follow up on any significant variances.***

We have compared the actual revenues from rates for 2018 to 2021 to assess any significant trends. The results of this analysis of revenue by rate class are as follows:

($000's)	2018	2019	2020	2021
Residential	$ 419,389	$ 432,272	$ 458,433	**$ 453,328**
General Service				
0-100 kW	90,364	93,038	93,282	**96,298**
110-1000 kVA	97,338	101,397	105,418	**107,731**
Over 1000 kVA	35,725	37,916	38,643	**36,428**
Streetlighting	16,255	16,664	16,983	**16,958**
Discounts forfeited	2,643	2,892	2,868	**2,560**
Revenue from rates	$ 661,714	$ 684,179	$ 715,627	**$ 713,303**
Year over year percentage change	-0.03%	3.39%	4.60%	**-0.32%**



The above graph demonstrates that the Company has seen a 0.32% decrease in revenue from rates in 2021 as compared to 2020. The decrease is primarily due to lower electricity sales from residential customers.

The comparison by rate class of 2021 actual revenues to 2021 budget is as follows:

($000's)	2020	2021	2021 Plan	Actual - Plan Variance	%
Residential	$ 458,433	**$ 453,328**	**$ 450,866**	$ 2,462	0.55%
General Service					
0-100 kW	93,282	**96,298**	**99,776**	(3,478)	(3.49%)
110-1000 kVA	105,418	**107,731**	**109,753**	(2,022)	(1.84%)
Over 1000 kVA	38,643	**36,428**	**41,636**	(5,208)	(12.51%)
Streetlighting	16,983	**16,958**	**16,887**	71	0.42%
Discounts forfeited	2,868	**2,560**	**2,880**	(320)	(11.11%)
Total revenue from rates	$ 715,627	**$ 713,303**	**$ 721,798**	$ (8,495)	(1.18%)

We have also compared the 2021 budget energy sales in GWh to the actual sold in 2021:

(GWH'S)	2020	2021	2021 Plan	Actual - Plan Variance	%
Residential	3,547.0	**3,499.2**	**3,481.9**	17.3	0.50%
General Service					
0-100 kW	749.4	**778.5**	**800.0**	(21.5)	(2.69%)
110-1000 kVA	990.2	**1,018.4**	**1,031.8**	(13.4)	(1.30%)
Over 1000 kVA	410.1	**388.3**	**443.9**	(55.6)	(12.53%)
Streetlighting	32.3	**30.6**	**30.9**	(0.3)	(0.97%)
Total	5,729.0	**5,715.0**	**5,788.5**	(73.5)	(1.27%)

Actual 2021 revenue from rates was lower than 2021 Plan with an overall decrease in actual sales of $8,495,000 (1.18%) from the 2021 Plan due to decreased electricity sales. There was a 1.27% decrease in GWh sold in 2021 compared to 2021 Plan which was primarily due to the lower average use by commercial customers due to the Covid-19 pandemic. The largest variance in revenue can be seen in the Over 1000 kVA, the 0-100 kW, and the Residential class where revenues decreased by $5,208,000 (12.51%), decreased by $3,478,000 (3.49%), and increased by $2,462,000 (0.55%), 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.***

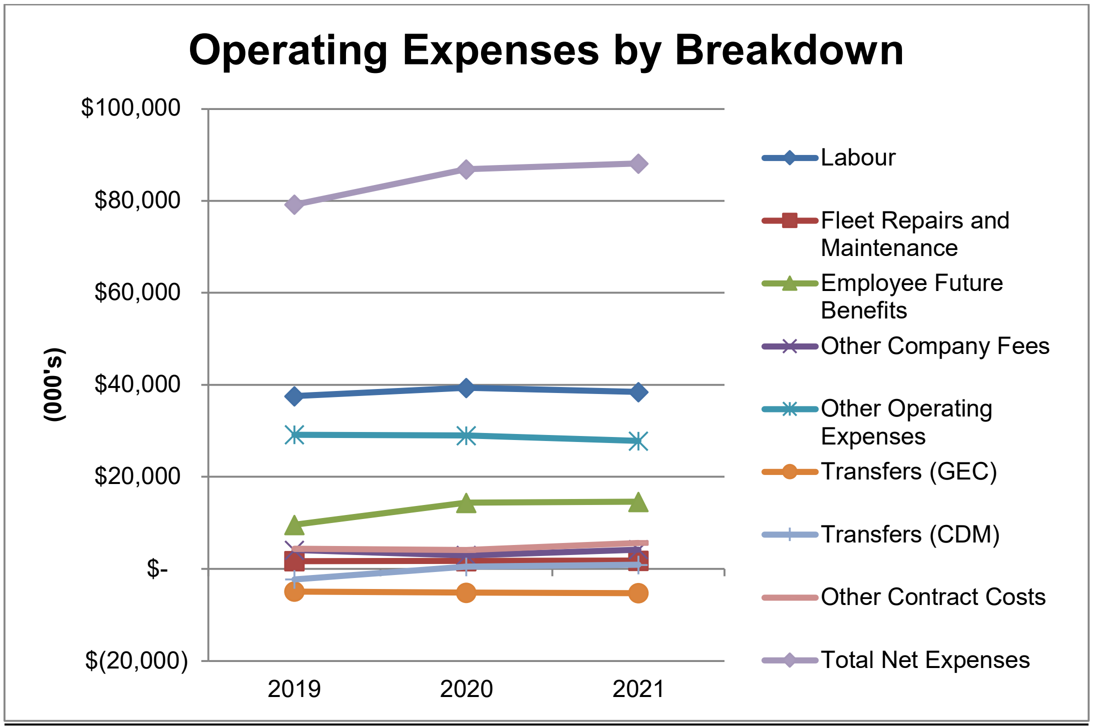
The below table provides details of operating and general expenses (including non-regulated expenses) by "breakdown" for 2019, 2020, and 2021.

(000's)	Actual 2021	Actual 2020	Actual 2019	Variance 2021-2020
Labour	$ 40,055	$ 40,652	$ 38,603	$ (597)
Reclass OPEB labour cost	(1,615)	(1,290)	(1,041)	(325)
Total Labour	38,440	39,362	37,562	(922)
Vehicle expense	1,813	1,725	1,681	88
Operating materials	1,075	1,301	1,361	(226)
Inter-company charges	1,995	2,277	2,058	(282)
Plants, Subs, System Oper & Bldgs	3,495	3,484	3,267	11
Travel	678	638	1,142	40
Tools and clothing allowance	1,143	1,156	1,289	(13)
Miscellaneous	1,882	1,999	2,005	(117)
Conservation	1,652	2,172	2,813	(520)
Taxes and assessments	1,337	1,116	1,156	221
Uncollectible bills	1,111	2,290	1,980	(1,179)
Insurance	1,995	1,698	1,397	297
Severance & other employee costs	(17)	126	132	(143)
Education, training, employee fees	338	275	444	63
Trustee and directors' fees	686	673	518	13
Other company fees	4,186	2,944	4,058	1,242
Stationary & copying	168	246	257	(78)
Equipment rental/maintenance	664	656	790	8
Communications	2,874	2,786	2,803	88
Advertising	1,412	1,264	1,581	148
Vegetation management	2,524	2,306	2,042	218
Computing equipment & software	2,461	2,199	1,830	262
Total Other	33,472	33,331	34,604	141
Pension & early retirement program	6,966	7,864	3,335	(898)
OPEB's	7,630	6,528	6,241	1,102
Total employee future benefits	14,596	14,392	9,576	204
Total gross expenses	86,508	87,085	81,742	(577)
Transfers (GEC)	(5,276)	(5,175)	(4,913)	(101)
CDM amortization	5,889	5,578	4,597	311
Other contract expenses	5,667	4,120	4,353	1,547
Deferred CDM program costs	(4,991)	(5,118)	(6,864)	127
Deferred regulatory costs	353	353	294	-
Total net expenses	**$ 88,150**	**$ 86,843**	**$ 79,209**	**$ 1,307**

Overall, net operating expenses increased by $1,307,000 from 2020 to 2021. 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 2021 are unreasonable.

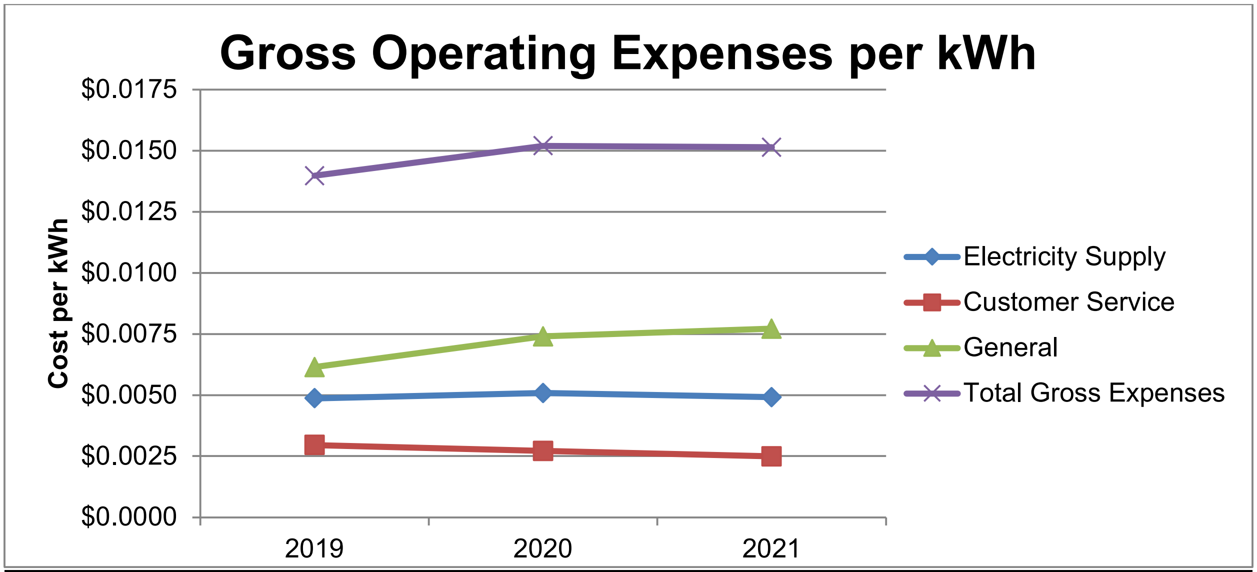
Our detailed review of operating expenses was conducted using the breakdown as documented in the above table. It should also be noted that our review is based upon gross expenses before allocation to GEC and CDM. The following table and graph show the trend in net operating expenses by breakdown for the period 2019 to 2021.

	Actual		
(000's)	2019	2020	2021
Labour	$ 37,562	$ 39,362	**$ 38,440**
Fleet Repairs and Maintenance	1,681	1,725	**1,813**
Employee Future Benefits	9,576	14,392	**14,596**
Other Company Fees	4,058	2,944	**4,186**
Other Operating Expenses	29,159	29,016	**27,826**
Transfers (GEC)	(4,913)	(5,175)	**(5,276)**
Transfers (CDM)	(2,267)	460	**898**
Other Contract Expenses	4,353	4,119	**5,667**
Total Net Expenses	$ 79,209	$ 86,843	**$ 88,150**



The relationship of operating expenses to the sale of energy (expressed in kWh) from 2019 to 2021 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
2019	5,846,600	$28,473	$0.0049	$17,298	$0.0030	$35,970	$0.0062	$81,742	$0.0140
2020	5,729,000	$29,144	$0.0051	$15,555	$0.0027	$42,386	$0.0074	$87,085	$0.0152
2021	5,715,000	$28,095	$0.0049	$14,282	$0.0025	$44,131	$0.0077	$86,508	$0.0151



The table and graph show that total gross expenses per kWh have decreased by approximately 0.7% compared to 2020.

There was an increase in General Costs of $1.7 million, with a decrease in Customer Service Costs of $1.3 million and a decrease in Electricity Supply Costs of $1.0 million. The results of our review of the individual significant expense categories variances are noted on the following pages.

Salaries and Benefits (including executive salaries)

A detailed comparison of the number of full-time equivalent (FTE) employees by category for 2019 to 2021 (including 2021 Plan) is as follows:

	Actual 2021	Plan 2021	Actual 2020	Actual 2019	Actual - Plan	Actual 2021-2020
Executive Group	**6.0**	**6.0**	6.0	6.2	-	-
Corporate Office	**22.2**	**21.2**	21.6	20.8	1.0	0.6
Finance	**97.4**	**100.1**	96.6	93.5	(2.7)	0.8
Engineering and Operations	**368.4**	**386.2**	382.7	383.2	(17.8)	(14.3)
Customer Relations	**95.0**	**92.3**	70.6	72.8	2.7	24.4
	589.0	**605.8**	577.5	576.5	(16.8)	11.5
Temporary employees	**18.5**	**21.2**	34	39.7	(2.7)	(15.5)
Total	**607.5**	**627**	611.5	616.2	(19.5)	(4.0)

The overall number of FTE's in 2021 compared to 2020 decreased by 4.0. The budgeted number of FTEs in the 2021 Plan was 627.0 versus actual of 607.5. The variances between 2021, 2021 Plan, and 2020 are the result of the following:

- Finance & Information Technology for 2021 is lower than plan primarily due to delayed hires to replace transfers to the CIS Project. 2021 is consistent with 2020.
- Engineering & Operations for 2021 is lower than plan and 2020 primarily due to delayed hires as a result of COVID-19.
- Customer Relations for 2021 is higher than plan primarily due to transfers in from the CIS Project, partially offset by delayed hires for Electrification Program. 2021 is higher than 2020 primarily due to a shift from temporary to regular employees and transfers in from the CIS Project.
- Temporary Employees for 2021 is lower than plan and 2020 primarily due to a shift from temporary to regular employees.

An analysis of salaries and wages by type of labour and by function from 2019 to 2021 is as follows:

(000's)	Actual 2021	Actual 2020	Actual 2019	Variance 2021-2020
Type				
Internal labour *(1)*	**$ 69,839**	$ 69,028	$ 66,023	$ 811
Overtime *(2)*	**6,635**	5,886	6,568	749
	76,474	74,914	72,591	1,560
Contractors *(3)*	**15,441**	12,510	17,523	2,931
	$ 91,915	$ 87,424	$ 90,114	$ 4,491
Function				
Operating *(4)*	**$ 40,055**	$ 40,652	$ 38,603	$ (597)
Capital and miscellaneous *(5)*	**51,860**	46,772	51,511	5,088
Total	**$ 91,915**	$ 87,424	$ 90,114	$ 4,491
Year over year percentage change	**5.14%**	-2.99%	3.50%	

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 2021 were $4,491,000 (5.14%) higher than 2020.

Note 1 - Internal labour for 2021 was higher than 2020 due primarily to inflationary increases.

Note 2 - Overtime labour for 2021 was higher than 2020 primarily due to higher overtime associated with (i) capital distribution work and (ii) capital generation work. This increase was partially offset by the overtime associated with restoration efforts required following storms in 2020.

Note 3 - Contract labour for 2021 was higher than 2020 due to higher labour for (i) transmission line rebuilds and deficiencies, and (ii) capital distribution work.

Note 4 - Operating labour for 2021 was lower than 2020 due primarily to shift to capital distribution work, partially offset by labour inflation and increased regulatory activity in 2021.

Note 5 - Capital and Miscellaneous labour for 2021 was higher than 2020 due primarily to higher contract labour for (i) transmission line rebuilds and deficiencies, and (ii) capital distribution work, as well as higher internal labour for capital distribution work.

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 2019 to 2021 are included in the table below:

	Salary Cost Per FTE			
	Actual 2021	**Actual 2020**	**Actual 2019**	**Variance 2021-2020**
Total reported internal labour costs	**$ 69,839**	$ 69,028	$ 66,023	$ 811
Benefit costs (net)	**(10,231)**	(9,563)	(8,926)	(668)
Other adjustments	**(989)**	(1,693)	(1,126)	704
Base salary costs	**58,619**	57,772	55,971	847
Less: executive compensation	**(1,985)**	(1,902)	(1,938)	(83)
Base salary costs (excluding executive)	**$ 56,634**	$ 55,870	$ 54,033	$ 764
FTE's (including executive members)	**607.5**	611.5	616.2	
FTE's (excluding executive members)	**603.5**	607.5	612.2	
Average salary per FTE	**96,492**	94,476	90,833	
% increase	**2.13%**	4.01%	1.48%	
Average salary per FTE (excluding executive members)	**93,842**	91,968	88,261	
% increase	**2.04%**	4.20%	1.10%	

The above analysis indicates that the rate of increase in average salary per FTE excluding executive members for 2021 has decreased from 2020, and 2020 increased from 2019.

The increase in average salary per FTE, including and excluding executive members, increased from 2020 to 2021 by 2.13% and 2.04% respectively. This increase is primarily a result of normal salary inflationary increases and progression.

Short Term Incentive (STI) Program

The following table outlines the actual results for 2019 to 2021 and the targets set for 2021:

Measure	Target 2021	Actual 2021	Actual 2020	Actual 2019
Controllable Operating Costs/Customer	**$ 240.20**	**$ 234.50**	$ 237.70	$ 231.00
Earnings	**$ 43.5M**	**$ 43.8M**	$ 43.2M	$ 42.3M
Cash Flow from Operating Activities	**$ 126.4M**	**$ 148.1M**	$ 136.8M	$ 111.2M
Reliability - Duration of Outages (SAIDI)	**2.50**	**2.48**	2.98	2.34
Customer Satisfaction - % Satisfied	**86.3%**	**88.3%**	87.6%	85.8%
Injury Frequency Rate	**0.74**	**0.56**	0.74	0.37

According to the Company, reliability targets and results exclude interruptions which are Hydro related and those which meet the Institute of Electrical and Electronics Engineers (IEEE) definition of significant events. 2019 STI results were adjusted to remove the impact of the severe weather conditions in February, September and November. In 2019 the 'regulatory performance' measure was replaced by the 'cash flow from operating activities' measure.

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	70%	30%
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 2021 is established as a percentage of base pay for the three employee groups. For 2021, all measures were met in comparison to their targets.

The following table illustrates the target as a percentage of base pay together with the actual STI payouts for 2019 to 2021:

	Target 2021	Actual 2021	Target 2020	Actual 2020	Target 2019	Actual 2019
President	**50%**	**69.77%**	50%	64.44%	50%	70.00%
Executive	**35%-40%**	**51.24%**	35%-40%	46.86%	35% - 40%	50.42%
Directors	**15%**	**20.90%**	15%	19.73%	15%	17.94%

STI actual payout rates for 'President', 'Executive', and 'Directors' employee groups are higher than the prior year. Each payout rate is exceeding targets, consistent with 2020 and 2019.

In dollar terms, the STI payouts for 2019 to 2021 are as follows:

	Actual 2021	Actual 2020	Actual 2019	Variance 2020-2019
President	**$ 277,000**	$ 265,000	$ 287,000	$ 12,000
Executive	**444,000**	402,000	416,000	42,000
Directors	**415,200**	357,800	311,000	57,400
Total	**$ 1,136,200**	$ 1,024,800	$ 1,014,000	$ 111,400
Year over Year % change	**10.87%**	1.07%	16.26%	

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 2021, the non-regulated portion (before tax adjustment) was $414,578 (2020 - $299,085). In 2019 the 'regulatory performance' measure was replaced by the 'cash flow from operating activities' measure where it is included in regulated expense at 100%. In Order No. P.U. 3 (2022), the Board ordered that the recovery of expenses associated with the cash flow component of the corporate target of the Company's STI program be capped at 50% effective January 1, 2022.

Executive Compensation

The following table provides a summary and comparison of executive compensation for 2019 to 2021:

	Base Salary	Short Term Incentive	Other	Total
2021				
Total executive group	$ 1,263,500	$ 721,000	$ 551,501	$ 2,536,001
Average per executive (4)	**$ 315,875**	**$ 180,250**	**$ 137,875**	**$ 634,000**
2020				
Total executive group	$ 1,269,105	$ 632,900	$ 1,339,435	$ 3,241,440
Average per executive (4)	**$ 317,276**	**$ 158,225**	**$ 334,859**	**$ 810,360**
2019				
Total executive group	$ 1,235,000	$ 703,000	$ 421,412	$ 2,359,412
Average per executive (4)	**$ 308,750**	**$ 175,750**	**$ 105,353**	**$ 589,853**
% Average increase 2021 vs 2020	-0.44%	13.92%	-58.83%	-21.76%
Per executive % average increase 2021 vs 2020	-0.44%	13.92%	-58.83%	-21.76%

Base salary for the executive group in 2021 decreased by 0.44% from 2020. In 2021, there was no changeover within the executive positions throughout the year, therefore four executives held positions for the entire year, resulting in four FTE.

Other compensation for the executive group in 2021 decreased from 2020, primarily due to the fact that there was no retention incentive pay required for 2021 as there was in 2020 due to the retiring CEO.

Company Pension Plan

For 2021, we reviewed the accounts supporting the gross charge of $6,966,000 of pension expense for the Company. A detailed comparison of the components of pension expense for 2019 to 2021 is below:

	Actual 2021	Actual 2020	Actual 2019	Variance 2021-2020
Pension expense per actuary	**$ 3,757,000**	$ 4,757,000	$ 639,000	$ (1,000,000)
Pension uniformity plan (PUP)/supplemental employee retirement program (SERP)	**379,000**	402,000	347,000	(23,000)
Group RRSP @ 2%	**307,000**	340,000	314,000	(33,000)
Individual RRSP's	**2,526,000**	2,371,000	2,055,000	155,000
Less: Refunds (net of other expenses)	**(3,000)**	(6,000)	(20,000)	3,000
Total	**$ 6,966,000**	$ 7,864,000	$ 3,335,000	$ (898,000)
Year over year percentage change	**(11.42%)**	135.80%	(10.94%)	

Overall, pension expense for 2021 is lower than 2020 primarily by lower interest costs as a result of a decrease in the discount rate. This is partially offset by an increase in actuarial loss amortization related to the decreased discount rate.

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 5.7% in 2021.

The employer’s portion of the contributions to the Group RRSP is calculated as 2.0% of the base salary paid to the plan participants. Individual RRSP contributions increased as a result of a plan amendment which increased the contribution rate from 6.25% to 6.50% as of January 2021. The closure of the Company’s Defined Benefit Plan in 2004 (the Group RRSP (2.0% Plan) also contributed to the increase. New hires are added to the Individual RRSP Plan whereas the majority of retirements are out of the Group RRSP Plan.

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 2019 to 2021 are as follows:

(000's)	Actual 2021	Actual 2020	Actual 2019	Variance 2021-2020
Accrued OPEBs	**$ 5,653**	$ 4,191	$ 3,657	$ 1,462
Amortization of transitional balance	**3,504**	3,504	3,504	-
Amount capitalized	**(1,527)**	(1,167)	(920)	(360)
Total	**$ 7,630**	$ 6,528	$ 6,241	$ 1,102

The increase in OPEB's expense from 2020 to 2021 is primarily due to lower amortization of past service credits, partially offset by lower interest costs associated with a decreased discount rate.

Intercompany Charges

Our review of intercompany charges included the following specific procedures:

- assessed the Company's compliance with Order Nos. P.U. 19 (2003), P.U. 32 (2007), P.U. 43 (2009), and P.U. 13 (2013);
- compared intercompany charges for the years 2020 to 2021 and investigated any unusual fluctuations;
- reviewed detailed listings of charges for 2021 and investigated any unusual items;
- vouched a sample of transactions for 2021 to supporting documentation;
- assessed the appropriateness of the amounts being charged; and
- reviewed the methodology developed by Fortis Inc. ("Fortis") in 2008 to allocate recoverable expenses to its subsidiaries.

The following table summarizes intercompany transactions from 2019 to 2021 for charges to and from Newfoundland Power:

	Actual 2021	Actual 2020	Actual 2019	Variance 2021-2020
Charges from related companies				
Regulated	**$ 700,744**	$ 220,017	$ 339,937	$ 480,727
Non-Regulated	**2,277,627**	2,587,867	2,360,484	$ (310,240)
Total	**$ 2,978,371**	$ 2,807,884	$ 2,700,421	$ 170,487
Charges to related companies	**$ 235,355**	$ 459,166	$ 1,214,048	$ (223,811)

Fortis bills its recoverable expenses on estimates rather than actual for the first three quarters of each year. Periodically, 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 assets.

We reviewed Fortis'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. As confirmed by the Company, there have been no significant changes to the methodology in 2021. Fortis estimated its net pool of operating expenses for 2021 based on the 2022-2026 business plan and is billed quarterly.

Actual recoverable expenses were determined to be $2,091,000 and are summarized as follows:

2021 Recoverable Expenses from Fortis Inc.

	Amount
Staffing and Staffing Related	$1,353,000
Director Fees and Travel	141,000
Consulting and Legal fees	129,000
Trustee Agent Fees	26,000
Annual Meeting Expenses	47,000
Insurance (D&O)	54,000
Other Costs	294,000
Total Quarterly Billings from Fortis Inc.	2,044,000
Less: 2020 True-Up	(49,000)
Plus: 2021 Q2 True-Up	96,000
	2,091,000
Less amounts previously billed:	
Q1 2021	806,000
Q2 2021	352,000
Q3 2021	536,000
True-Ups	47,000
Q4 2021 balance owing	$ 350,000

According to the Company, 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. Total quarterly billings from Fortis Inc. as shown above were $2,091,000. There were also additional invoices of $839,683 received directly from Fortis during 2021 for total Fortis charges of $2,930,683 ($2,091,000+$839,683), of which $653,056 were regulated and $2,277,627 were non-regulated. 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, as well as other related parties. The following table summarizes the various components of the regulated intercompany transactions for 2019 to 2021 with Fortis:

(Regulated)	Actual 2021	Actual 2020	Actual 2019	Variance 2021-2020
Charges from Fortis Inc.				
Trustee fees and share plan costs	**$ 31,000**	$ 20,000	$ 27,000	$ 11,000
Staff Charges	**60,276**	-	40,884	60,276
Miscellaneous	**561,780**	136,856	208,765	424,924
	$ 653,056	$ 156,856	$ 276,649	$ 496,200
Year over year percentage change	**316.34%**	(43.30%)	(73.88%)	
Charges to Fortis Inc.				
Postage and couriers	**$ 1,501**	$ 1,640	$ 2,181	$ (139)
Staff charges	**75,695**	23,546	51,573	52,149
Miscellaneous	**35,937**	58,704	31,561	(22,767)
	$ 113,133	$ 83,890	$ 85,315	$ 29,243
Year over year percentage change	**34.86%**	(1.67%)	(33.62%)	

The most significant fluctuations from our analysis of regulated charges from Fortis are an increase in the staff charges account of $60,276 and an increase in the miscellaneous account of $424,924. According to the Company, the fluctuation in staff charges is due to a Fortis employee on secondment returning to Newfoundland Power from July to October 2021. The fluctuation in the miscellaneous amount is due to a DC SERP payment of $162,255 paid to an employee upon retirement as well as $258,065 of Microsoft Canada Inc. invoices paid by Fortis on Newfoundland Power's behalf.

The most significant fluctuations from our analysis of regulated charges to Fortis are an increase in staff charges of $52,149 and a decrease in miscellaneous charges of $22,767. The increase in staff charges is due to a Newfoundland Power employee working with the Fortis Operating group and the decrease in miscellaneous charges is because there was a higher-than-normal balance in 2020 from short-term incentive payments relating to employee transfers between Fortis Inc. and Newfoundland Power in 2019.

The following table provides a summary and comparison of the non-regulated intercompany transactions for 2019 to 2021:

(Non-Regulated)	Actual 2021	Actual 2020	Actual 2019	Variance 2021-2020
Charges from Fortis Inc.				
Director's fees and travel	**$ 135,000**	$ 170,000	$ 178,000	$ (35,000)
Staff charges	**1,438,000**	1,602,000	1,294,000	(164,000)
Miscellaneous	**704,627**	815,867	888,484	(111,240)
	$ 2,277,627	$ 2,587,867	$ 2,360,484	$ (310,240)

Staff charges have decreased from 2020 by $164,000 primarily due to a decrease in non-regulated staff charges from Fortis Inc.

Miscellaneous charges decreased by $111,240. According to the Company this is because of a $97,286 Restricted Share Unit ("RSU") payment in 2020 that was paid to an employee upon retirement.

The following table provides a summary and comparison of the other intercompany transactions for 2019 to 2021:

Intercompany Transactions (Other)	Actual 2021	Actual 2020	Actual 2019	Variances 2021-2020
Charges to Fortis Ontario Inc.				
Staff charges	**$ 2,685**	$ 105,907	$ 390,837	$ (103,222)
Miscellaneous	**48,018**	219,076	326,592	(171,058)
	$ 50,703	$ 324,983	$ 717,429	$ (274,280)
Charges from Fortis Ontario Inc.				
Miscellaneous	**$ -**	$ -	$ 4,875	$ -
Charges to Maritime Electric				
Staff charges	**$ -**	$ 997	$ 276,106	$ (997)
Miscellaneous	**13,780**	36,305	78,496	(22,525)
	$ 13,780	$ 37,302	$ 354,602	$ (23,522)
Charges from Maritime Electric				
Miscellaneous	**$ -**	$ 11,406	$ 6,193	$ (11,406)
Charges to Central Hudson Gas & Electric				
Staff charges	**$ -**	$ -	$ 6,321	$ -
Charges from Central Hudson Gas & Electric				
Miscellaneous	**$ -**	$ 4,068	$ 10,190	$ (4,068)

Intercompany Transactions (Other) Cont'd.	Actual 2021	Actual 2020	Actual 2019	Variances 2021-2020
Charges to Belize Electric Company Ltd.				
Staff charges	**$ 15,599**	$ 12,991	$ 35,226	$ 2,608
Miscellaneous		-	475	-
	$ 15,599	$ 12,991	$ 35,701	$ 2,608
Charges to FortisAlberta Inc.				
Miscellaneous	**$ 9,960**	$ -	$ 5,000	$ 9,960
Charges from FortisAlberta Inc.				
Miscellaneous	**$ 37,612**	$ 37,612	$ 37,612	$ -
Charges to FortisBC Inc./ Fortis BC Holdings				
Miscellaneous	**$ 19,430**	$ -	$ 9,680	$ 19,430
Charges from FortisBC Inc./ FortisBC Holdings				
Miscellaneous	**$ 10,076**	$ 10,075	$ 4,418	$ 1
Charges to Fortis Turks and Caicos				
Miscellaneous	**$ 12,750**	$ -	$ -	$ 12,750

The most significant fluctuations from our analysis of other intercompany charges for 2021 compared to 2020 are as follows:

- Staff charges to Fortis Ontario Inc. decreased by $103,222 in 2021. This decrease was due to a Newfoundland Power employee accepting a position with Fortis Ontario.
- Miscellaneous charges to Fortis Ontario Inc. decreased by $171,058 in 2021. This decrease was due to a short-term incentive payment of $171,666.
- Miscellaneous charges to Maritime Electric decreased by $22,525. This was due to a decrease in RSUs and Performance Share Units ("PSU") payments of $23,615 from 2020 to 2021.
- Miscellaneous charges to Fortis Alberta Inc. increased by $9,960 in 2021. This increase was due to 2020 Conference Board of Canada charges which were processed in Q1 of 2021.
- Miscellaneous charges to Fortis BC Inc./Fortis BC Holdings increased by $19,430. This increase was also due to 2020 Conference Board of Canada charges which were processed in Q1 of 2021.
- Miscellaneous charges to Fortis Turks and Caicos increased by $12,750 in 2021. This increase was due to the sale and shipment of 200 electric utility meters from Newfoundland Power to Fortis Turks and Caicos.

Loans to Related Parties

The Company entered into short-term borrowing agreements comprised of the following loans to related parties:

Company Name	Amount	Date Funds Advanced	Repayment Date	Amount Repaid *(1)*	Interest Rate	Total Interest Paid
Fortis Inc.	$ 8,000,000	December 8, 2020	January 20, 2021	$ 8,000,000	1.22875%	$ 11,580
Fortis Inc.	$ 10,000,000	January 29, 2021	February 22. 2021	$ 10,000,000	1.17750%	$ 7,742
Fortis Inc.	$ 5,000,000	February 4, 2021	February 22, 2021	$ 5,000,000	1.17750%	$ 2,903
						$ 22,226

(1) Excludes interest paid on loan.

According to the Company, the interest rate is based on the one-month Canadian Dollar Offered Rate (“CDOR”) set on January 29, 2021 and February 4, 2021 plus an 120 bps stamping fee which is the same as the credit facility, minus 24 bps for a standby fee charge which is the unused portion of the credit facility, and an additional discount of 20 bps. The 20 bps is a discount applied to loans to inter-affiliate companies. When an inter-affiliate loan is provided to Newfoundland Power, the same discount of 20 bps is applied. According to the Company, it is verified in all circumstances that the final loan rate is below available market rates, and that loans to and from an affiliate are only executed if it can be shown to be a positive benefit from a customer perspective.

Loans from Related Parties

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

In Order No. P.U. 19 (2003), the Board provided instructions to the Company with respect to the recording and reporting of intercompany transactions. Some of these instructions required reports to be filed with the Board at various times in 2021. It has been confirmed that quarterly reports relating to intercompany transactions have been filed for 2021.

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 2021 and vouching of a sample of individual transactions to supporting documentation.

(000's)	Actual 2021	Actual 2020	Actual 2019	Variance 2021-2020
Other company fees				
Other company fees	**$ 3,118**	$ 2,760	$ 3,746	$ 358
Regulatory hearing costs	**1,068**	184	312	884
	$ 4,186	$ 2,944	$ 4,058	$ 1,242
Year over year percentage change	**42.2%**	-27.5%	20.1%	
Deferred regulatory costs				
Total deferred regulatory costs	**$ 353**	$ 353	$ 294	$ -
Year over year percentage change	**0.0%**	20.1%	-13.8%	

Other Company Fee costs for 2021 were higher than 2020. According to the Company, this is primarily due to increased external consultant costs associated with customer energy conservation programs.

Regulatory hearing costs for 2021 were also higher than 2020. This is primarily a result of the Company's 2022/2023 General Rate Application filed on May 27th, 2021, as well as increased costs associated with the 2021 and 2022 Capital Budget Applications.

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 2019 to 2021 is as follows:

(000's)	Actual 2021	Actual 2020	Actual 2019	Variance 2021-2020
Miscellaneous	**$ 1,248**	$ 1,459	$ 1,231	$ (211)
Cafeteria and lunchroom Supplies	**39**	48	75	(9)
Promotional items	**99**	88	169	11
Computer Software	**2**	5	3	(3)
Damage claims	**248**	206	278	42
Community relations activities	**-**	1	1	(1)
Donations and charitable advertising	**168**	132	195	36
Books, magazines and subscriptions	**46**	24	18	22
Miscellaneous lease payments	**32**	36	35	(5)
Total miscellaneous expenses	**$ 1,882**	$ 1,999	$ 2,005	$ (118)
Year over year percentage change	**(5.88%)**	(0.30%)	23.84%	

Miscellaneous expenses by their very nature can fluctuate from year to year. From 2020 to 2021 these expenses have decreased by 5.88% overall.

Our procedures in this expense category for 2021 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 2021 expenses are unreasonable.

Conservation and Demand Management (CDM)

In compliance with Order No. P.U. 7 (1996-97), the Company filed the 2021 Conservation and Demand Management Report with the Board. This report provided a summary of 2021 CDM activities and costs as well as the outlook for 2022.

In 2021, Newfoundland and Labrador Hydro and Newfoundland Power ("the Utilities") also finalized the joint Five-Year Conservation Plan: 2021-2025 (the "2021 Plan"), which was filed with the Board on December 16, 2020 and continues longstanding CDM programs while also introducing electrification programs. The 2021 Plan focuses on electrification, conservation and demand management activities for the next five years, and features capital investment, program expansion and continued education efforts.

In 2021, CDM programs were implemented by the Utilities in a manner consistent with the 2021 Plan.

A breakdown of CDM costs in 2021 and 2020 is as follows:

($000's)	2021	2020	Variance - 2021-2020
General Costs			
Customer Education and Support	$ 489	$ 429	$ 60
Planning	262	429	(167)
Total General Costs	751	858	(107)
Program Costs			
Insulation Program	1,176	1393	(217)
Thermostat Program	294	324	(30)
HRV Program	205	157	48
Benchmarking Program	974	770	204
Instant Rebates Program	1,020	973	47
Low Income Program	103	0	103
Business Efficiency Program	1,035	1344	(309)
Total Program Costs	4,807	4,961	(154)
Capital Costs			
CDM Capital Expenditures	41	57	(16)
Other Costs			
Curtailable Service Option	403	398	5
Total Costs	$ 6,002	$ 6,274	$ (272)

CDM costs in 2021 totaled $6,002,000 compared to $6,274,000 in 2020, a $272,000 decrease. Conservation costs are lower than in 2020 primarily due to decreased program participation driven by COVID-19 related impacts on local businesses.

In 2021, $4,991,000 ($3,494,000 after tax) in CDM costs were deferred. CDM amortization for 2021 was $5,889,000 (2020- $5,578,000).

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

General Expense Capitalized (GEC)

($000's)	Actual 2021	Actual 2020	Actual 2019	Variance 2021-2020
Transfers (GEC)	**(5,276)**	(5,175)	(4,913)	(101)

The capitalization of pension costs has been reflected through the Company's General Expenses Capitalized ("GEC") account based on the GEC methodology approved by the Board in Order No. P.U. 3 (1995-96). In that Order, it was noted that Newfoundland Power was the only utility that included pension costs in a GEC allocation.

In Order No. P.U. 2 (2019), the Board approved the Company's proposal to increase the allocation of pension costs to GEC from 11% to 46%, to comply with Accounting Standards Update 2017-07 – *Improving the Presentation of Net Periodic Pension Costs and Net Periodic Post-Retirement Benefit Cost*, issued in March 2017 by the Financial Accounting Standards Board (the "Update"). This Update provided guidance that the amount of current service pension cost capitalized should reflect the proportion of labour costs that are related to capital work. Utilities that capitalize pension costs using a labour loader would already follow the proportion of labour costs that are related to capital work and therefore would not have been impacted by this Update.

In Order No. P.U. 3 (2022) the Board approved a change in the methodology from capitalizing pension costs from the indirect method via general expenses capitalized to the direct method via labour loader. This change is set to take effect on January 1, 2023.

Other Operating 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 2021 and 2020.

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

($000's)	Actual 2021	Actual 2020	Actual 2019	Variance 2021-2020
Vehicle expense	**1,813**	1,725	1,681	88
Operating materials	**1,075**	1,301	1,361	(226)
Inter-company charges	**1,995**	2,277	2,058	(282)
Plants, Subs, System Oper & Bldgs	**3,495**	3,484	3,267	11
Travel	**678**	638	1,142	40
Tools and clothing allowance	**1,143**	1,156	1,289	(13)
Conservation	**1,652**	2,172	2,813	(520)
Taxes and assessments	**1,337**	1,116	1,156	221
Uncollectible bills	**1,111**	2,290	1,980	(1,179)
Insurance	**1,995**	1,698	1,397	297
Severance & other employee costs	**(17)**	126	132	(143)
Education, training, employee fees	**338**	275	444	63
Trustee and directors' fees	**686**	673	518	13
Stationary & copying	**168**	246	257	(78)
Equipment rental/maintenance	**664**	656	790	8
Communications	**2,874**	2,786	2,803	88
Advertising	**1,412**	1,264	1,581	148
Vegetation management	**2,524**	2,306	2,042	218
Computing equipment & software	**2,461**	2,199	1,830	262
Other contract expenses	**5,667**	4,120	4,353	1,547

1. Operating materials for 2021 were lower than 2020 primarily due to lower materials for street light maintenance as a result of the LED Streetlight Replacement program.
2. Intercompany charges for 2021 were lower than 2020 due to lower recoveries from Fortis.
3. Conservation costs for 2021 were lower than 2020 due to lower customer energy conservation rebates and the ongoing review of the 2021 Conservation and Demand Management Plan.
4. Taxes and assessments for 2021 were higher than 2020 due to lower public utilities assessments received on the 2019/20 annual assessment invoice.
5. Uncollectible bills for 2021 were lower than 2020 primarily as a result of improved aging of receivables and improved collection activities.
6. Insurance costs for 2021 were higher than 2020 due primarily to higher premium rates for property insurance.
7. Vegetation management costs for 2021 were higher than 2020 due to additional transmission and distribution vegetation management in 2021.
8. Computing equipment & software costs for 2021 were higher than 2020 due to increases in third party software licensing costs.
9. Other contract expenses include the costs associated with provisioning work from third-party telecommunication companies which increased in 2021 compared to 2020.

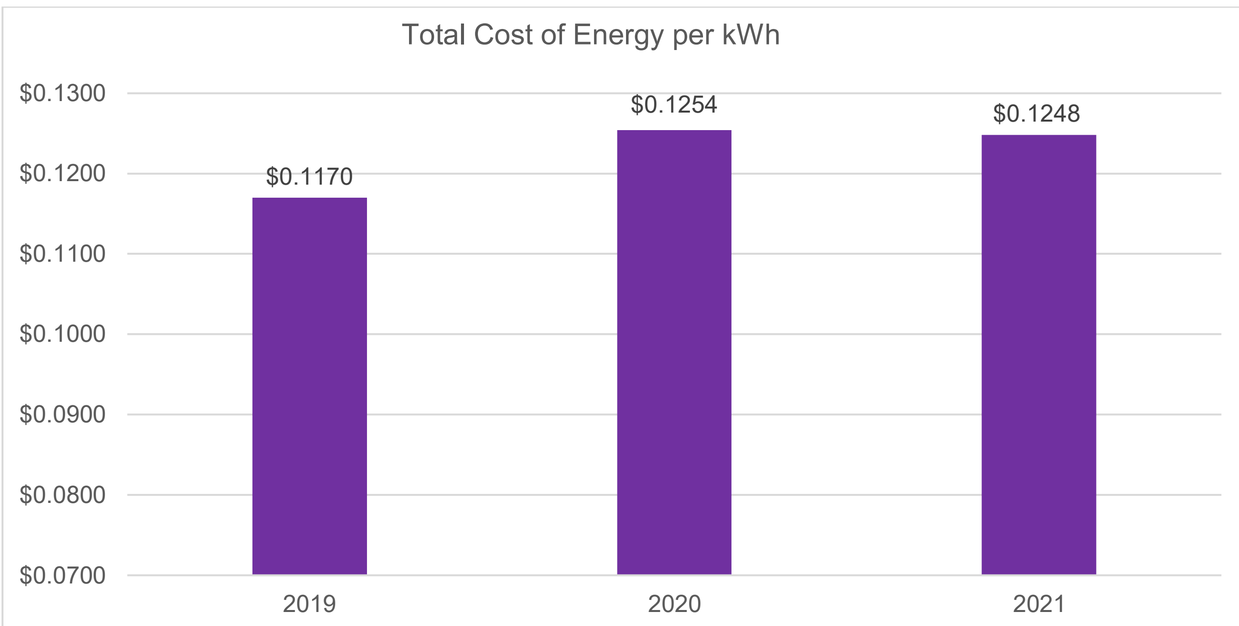
Other Costs

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 2019 to 2021:

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
2019	5,846,600	$79,209	$444,861	$1,752	$68,019	$35,931	$11,299	$42,891	$683,962	$0.1170
2020	5,729,000	$86,844	$468,844	($876)	$71,187	$37,146	$11,893	$43,577	$718,614	$0.1254
2021	**5,715,000**	**$88,150**	**$461,393**	**($876)**	**$73,993**	**$35,311**	**$11,603**	**$43,757**	**$713,331**	**$0.1248**



Purchased Power

We have reviewed the Company's purchased power expense for 2021 and have investigated fluctuations and changes. We performed a recalculation of the purchased power and investigated Hydro bills 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 $7.5 million, from $468.8 million in 2020 to $461.3 million in 2021. According to the Company, the costs were lower in 2021 primarily due to lower energy purchases and lower electricity system losses.

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 2021 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 2021; and,
- assessed the overall reasonableness of the depreciation for 2021.

Amortization expense for 2021 is $73,993,000 as compared to $71,187,000 for 2020, representing a 3.9% increase. The 2021 and 2020 depreciation expense exclude 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:

			Variance	
(000's)	**2021**	**2020**	**2021-2020**	**%**
Depreciation and amortization as reported	**$73,993**	$71,187	$2,806	3.9%
Less: Tax on Cost of Removal (1)	**(6,447)**	(6,205)	(242)	3.9%
Depreciation of Fixed Assets	**$67,546**	$64,982	$2,564	3.9%

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

Depreciation of fixed assets for 2021 is $67,546,000 as compared to $64,982,000 for 2020, representing a 3.9% increase. The change is attributable to an increase of depreciable assets by approximately $83,499,000. The following table provides a comparison of the depreciation of fixed assets for 2021, 2020, and 2019:

(000's)	2021	2020	2019	Variance 2021-2020	Variance 2020-2019
Depreciation of Fixed Assets	**$67,546**	$64,982	$62,066	$2,564	$2,916

Note – A new depreciation study, based on the Company's electric plant as of December 31, 2019 was approved in Order No. P.U. 3 (2022), with effect from January 1, 2022.

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), Order No. P.U. 18 (2016), and Order No. P.U. 2 (2019). 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 2021.

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 results of our procedures have been outlined below.

The following table summarizes the various components of finance charges expense for the years 2019 to 2021:

(000's)	Actual 2021	Actual 2020	Actual 2019	Variance 2021-2020
Interest				
Long-term debt	**$ 35,450**	$ 36,811	$ 35,375	$ (1,361)
Other	**190**	624	1,384	(434)
Amortization				
Debt discount	**217**	233	235	(16)
Interest charged to construction	**(546)**	(522)	(1,063)	(24)
Total Finance charges	**$ 35,311**	$ 37,146	$ 35,931	$ (1,835)
Year over year percentage change	**(4.94%)**	3.38%	(0.78%)	

The following observations were made with respect to the more significant fluctuations in finance charges:

- There were no new debt issues in 2021 for long-term debt.
- The decrease in long-term debt interest is primarily due to a reduction in average debt in 2021 compared to 2020 due to the repayment of bond issuance series AG of $30,000,000 in October 2020 and annual sinking fund payments on existing debt.

Based upon our analysis, nothing has come to our attention to indicate that the finance charges for 2021 are unreasonable.

Income Tax Expense

We have reviewed the Company's income tax expense for 2021 and have noted that the effective income tax rate decreased from 21.4% in 2020 to 21.0% in 2021. Actual income tax expense in 2021 and 2020 results in the following effective rates:

	2021	2020	2019	2021-2020
Income tax expense	**$ 11,603**	$ 11,893	$ 11,299	$ (290)
Earnings before income tax	**$ 55,360**	$ 55,470	$ 54,190	$ (110)
Effective income tax rate	**21.0%**	21.4%	20.9%	(0.4%)

Income tax expense decreased by $290,000 compared to 2020. The statutory tax rate was 30.0% for both 2021 and 2020.

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 2021 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 $391,149 for the current period compare to a total of $384,831 for the same period during the previous year. According to the Company, the credit total for the 2020-2021 winter season is higher than the previous season total primarily due to variations in Option participant's demand and consumption as well as the mix of Option participants achieving full, partial, or no credit.

Nothing has come to our attention to indicate that the Company is not in compliance with 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 2021 to prior years and investigated any significant fluctuations;
- reviewed detailed listings of expenses for 2021 and investigated any significant 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 2021	Actual 2020	Actual 2019	Variance 2021-2020
Charged from Fortis Companies	**$ 1,969,435**	$ 2,251,000	$ 2,115,024	$ (281,565)
Performance and restricted share units	**899,513**	1,083,018	665,058	(183,505)
Donations and charitable advertising	**248,294**	210,426	336,662	37,868
Executive short term incentive	**469,303**	576,510	419,479	(107,207)
Miscellaneous	**14,681**	10,934	40,265	3,747
	3,601,226	4,131,888	3,576,488	(530,662)
Less: Income Taxes	**1,080,368**	1,239,566	1,072,946	(159,198)
Total non-regulated (net of tax)	**$ 2,520,858**	$ 2,892,322	$ 2,503,542	$ (371,464)

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 2021, this represents an addition to non-regulated expenses (before tax adjustment) of $469,303 (2020 - $576,510). However, it should be noted that these Orders were issued prior to the replacement of the regulatory performance measure with the cash flow performance measure in 2019; the cash flow measure is included in regulated expense at 100% of target. In Order No. P.U. 3 (2022), the Board ordered that the recovery of expenses associated with the cash flow component of the corporate target of the Company's STI program be capped at 50% effective January 1, 2022. 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 2021 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 2020 and 2021:

(000's)	2021 Actual	2020 Actual	Variance 2021-2020
Regulatory Assets			
OPEBs asset (ii)	**$ 14,016**	$ 17,520	$ (3,234)
Deferred GRA costs (iii)	**-**	353	(353)
Conservation and demand management deferral (iv)	**23,458**	24,356	(898)
Demand management incentive (v)	**1,917**	1,431	486
Employee future benefits (vi)	**21,397**	74,752	(53,355)
Deferred income taxes (viii)	**234,715**	227,450	7,265
	$ 295,503	$ 345,862	$ (50,088)
Regulatory Liabilities			-
Rate stabilization account (i)	**$ 32,466**	$ 22,035	$ 10,431
Cost recovery deferral (ix)	**-**	876	(876)
Weather normalization account (vii)	**2,885**	5,333	(2,448)
Future removal and site restoration provision (x)	**187,622**	178,469	9,153
	$ 222,973	$ 206,713	$ 16,260

(i) Rate Stabilization Account

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. On June 17, 2020, in Order No. P.U. 16 (2020), the Board approved a wholesale bill credit of approximately $50.6 million. In Order No. P.U. 17 (2020), the Board approved the one-time bill credit of approximately $47.7 million to eligible customers. This resulted in no change to customer electricity rates effective July 1, 2020.

As of December 31, 2021, there was a refund to customers transferred to the RSA of $25,413,219 related to the Energy Supply Cost Variance Reserve in accordance with Order No. P.U. 32 (2007) and Order No. P.U. 43 (2009).

Pursuant to Order No. P.U. 31 (2010), the Board approved the Company's proposal to create the 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 31st in the year in which the difference arises. As of March 31, 2021, the credit balance of $1,419,980 in the OPEBVDA account was transferred to the RSA, as approved in Order No. P.U. 16 (2013).

Pursuant to Order No. P.U. 43 (2009), the Board approved the Company's proposal to create a 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, 2021, the balance of $5,539,105 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 RSA. As of March 31, 2021, $5,333,581 was debited and $5,889,287 was 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 for $1,431,126 as approved in Order No. P.U. 14 (2021).

(ii) Other Post-Employment Benefits

The 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 $52.6 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).

(iii) Deferred general rate application costs

In Order No. P.U. 2 (2019), the Board approved the deferral of cost related to 2019/2020 GRA as well as amortization of this deferral over a 34-month period commencing on March 1, 2019 and ending December 31, 2021. Estimated costs were $1,000,000 with amortization of $353,000 incurred in 2021.

(iv) 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 RSA. The actual costs incurred and deferred at December 31, 2021 were $23,458,000 with amortization of $5,889,287 in 2021.

In Order No. P.U. 3 (2022), the Board approved the amortization of annual costs over 10 years, commencing January 1, 2021 for historical balances and annual charges. The implementation of Order No. P.U. 3 (2022) resulted in a $1,875,000 true-up increase in deferred conservation costs in 2022 relating to annual deferred customer energy conservation program costs incurred up to December 31, 2021.

(v) Demand Management Incentive

In Order No. P.U. 32 (2007), the Board approved the Company's proposal to create the Demand Management Incentive Account to replace the Purchased Power Unit Cost Variance Reserve. This account aims to isolate the demand costs and is equal to plus or minus 1% of test year wholesale demand charges. The Demand Management Incentive as at December 31, 2021 was $1,917,000 ($1,342,000 after tax).

(vi) 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:

- 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,
- 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, 2021, the regulated asset for employee future benefits was $21,397,000.

(vii) 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 RSA at March 31st of the following year. In Order No. P.U. 11 (2022), the Board approved the December 31, 2021 net regulatory liability balance in the Weather Normalization Account of $2,885,000 ($2,020,000 net of deferred income tax).

(viii) 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, 2021 was $234,715,000.

(ix) Cost Recovery Deferral

In 2019, there was an over-recovery of revenue due to a March 1, 2019 rate implementation date. In Order No. P.U. 2 (2019), the Board approved amortization over a 34-month period from March 1, 2019 to December 31, 2021 to provide recovery in customer rates of any 2019 revenue shortfall/over-recovery associated with the March 1, 2019 rate implementation. The over-recovery of revenue was approximately $2,482,000 with the full amount having been amortized as of December 31, 2021. The net regulating liability for deferred costs – 2019 Cost Recovery Deferral at December 31, 2021 was $Nil.

(x) 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 2021, the balance in this account was $187,622,000 (2020 - $178,469,000).

Based upon our analysis, nothing has come to our attention to indicate that changes in regulatory deferrals for 2021 are unreasonable.

Pension Expense Variance Deferral Account

Scope: ***Review of calculation of the Pension Expense Variance Deferral Account 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 RSA as of the 31st day of March in the year in which the difference arises.

The 2021 PEVDA was calculated at $5,539,106. This balance was transferred to the RSA as a charge on March 31, 2021 in accordance with Order No. P.U. 43 (2009).

We confirm that the 2021 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 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 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 RSA as of the 31st day of March in the year in which the difference arises.

The 2021 OPEBVDA was calculated at $1,419,980. This balance was transferred to the RSA as a charge on March 31, 2021 in accordance with Order No. P.U. 31 (2010).

We confirm that the 2021 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 2021 are as follows:

1. Made capital investments of $109 million of which over 55% 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 with the installation of down line reclosers to provide for improved control of the distribution system along with improving the ability to locate and isolate system trouble.
6. Began collaboration with the Electric Power Research Institute ("EPRI") to test drones as an innovative solution for transmission and distribution line inspections. Using drones has the potential to improve safety, increase inspection quality and reduce costs over the long-term.
7. Began implementation of electronic logging devices on all heavy fleet vehicles. These are typically used in commercial motor vehicles to record driving time and hours of service automatically, as well as to capture data on the vehicle's engine, movement and distance driven. The new system, from GeoTab, will replace the Company's existing Record of Duty and Truck Inspection forms, in compliance with current federal and provincial regulations. It will also be leveraged to provide future benefits such as tracking vehicle idling time and reducing fuel costs, assessing driver behavior to improve safety and analyzing fleet data to improve operational efficiency and fleet availability.
8. Completed development of a Climate Adaptation Plan and Clean Energy Plan. The Plan details a strategy to manage and prepare for the impacts of climate change including extreme wind, ice and snowstorms, flooding and wildfires.
9. Completed the initial installation of hardware for a pilot of smart-city street lighting in Mount Pearl. The pilot project utilizes dynamic lighting controllers and radar sensors to provide traffic data. Software installation and security measures are in progress, and provision of tailored reports for the city began in the first quarter of 2022.
10. Upgrades to the Company's Geographic Information System and Outage Management System were completed in 2021. The upgrades will ensure both systems function in a reliable and stable manner, are fully supported by the vendor and will also provide several improvements, such as enhanced tracking of incidents of wires down when there is no power outage.
11. Integrated the Outage Management System with the Geographical Information System providing for more accurate and precise analysis of outage data.
12. Implemented a 6-year program to replace all HPS street light fixtures with LED fixtures. The program will result in lower customer rates as a result of lower energy and maintenance costs for LED streetlights. LED streetlights also provide more reliable and better quality lighting for customers.

13. Provided web-based access to contractor owned vehicles and computers. This is particularly useful for assigning work.

14. Work concluded on revising core safety code training to be delivered to employees, including developing new testing procedures to ensure comprehension and ability to apply core safety code principles.

15. Engaged an industrial psychologist to develop training for operational employees aimed at increasing situational awareness and avoiding distractions to stay focused safely on work tasks. The program gives employees techniques to increase their attention span and ability to focus, problem solve and manage stress, emotions and improve their overall mental health.

16. Collaborated with HSE Integrated Ltd. to develop fall protection training specific to Power Line Technicians.

17. Held firefighter and first responder electrical safety seminar and in-class school presentations. The Company reached a total of 888 students in 2021 through the Youth Electrical Safety program.

18. Initiatives aimed at improving safety performance this year included tracking of new quality leading indicators. In particular these target the quality of completed work and completed tailboard discussions.

19. New applications of Geographic Information Systems ("GIS") technology were implemented to enable safer back country travel to access transmission lines. A project was started to map safe off-road routes for accessing and travelling transmission line rights-of-way. The new maps identify nearby water bodies and hazards such as bog holes and steep inclines and the safe routes will guide travel on snowmobiles, ATVs and other off-road equipment.

20. Implemented a new internet-based service that allows an agent to validate customer identification remotely, online or over the phone. eIDverifier, a service offered by Equifax, has resulted in a lower fraud risk factor and decreased email volumes while providing improved and least cost service delivery.

21. Newfoundland Power and Bell are working together to improve the customer experience related to vegetation management requests, specifically in areas where Bell is responsible for this service. Newfoundland Power now completes all customer-requested vegetation control in these areas, utilizing the Company's customer contact center, field staff and contractors. Related costs are billed back to Bell. Improved service consistency and responsiveness is anticipated to relieve frustration expressed by customers in recent years.

22. A number of enhancements were made to the Company's customer satisfaction monitoring. A new dashboard was completed that allows improved access to customer satisfaction data. Rather than wait for quarter end to receive customer survey results, interim results are available throughout the quarter using the new dashboard. This provides early insight into customer satisfaction, allowing the Company the opportunity to make improvements.

23. The procurement phase of the CIS replacement project is nearing completion. A software vendor was selected through the request for proposal process in 2021 and negotiations with the vendor were successfully concluded. A contract has been signed with Oracle Corporation for the majority of the software components of the Customer-to-Meter CIS solution.

24. In response to a number of telecommunications network outages over the past year, the Company expanded its business continuity infrastructure by adding 12 new backup hard-wired phone lines for its customer contact centre. This expansion now allows for a total of 20 phone lines for agents to receive calls outside the interactive voice response system in the event of a network outage.

25. The Company continued to support its customers in 2021 by allowing outstanding bills to be paid on more flexible payment terms.

26. Customer email traffic grew by 27% in 2021, to over 167,000 emails received. To ensure quality customer service delivery, Newfoundland Power continues to survey customers to obtain feedback on their email transaction experience.

27. A new dashboard was implemented to provide improved awareness of outstanding customer accounts by location. Using the new dashboard, field services staff deployment can be prioritized based on customers' account status and amounts owing and organized by geographic location.

28. A new key accounts program was launched targeting larger commercial customers (rate class 2.3 and 2.4). The program is meant to add value for these customers by improving service delivery and offering more personalized service to help meet their needs. As part of the program, the first edition of the quarterly What's Happening newsletter was distributed to over 950 commercial customers.

29. Regular phishing security tests were conducted throughout the year. Employee phishing training and testing results were above industry peer results. Newfoundland Power had an average pass rate of 99.1%, compared to the industry average of 95.3%.

30. The Company's perimeter (internet) firewall and SCADA firewalls were replaced. This initiative increases Newfoundland Power's ability to detect threats in network traffic.

31. Work was completed on segmenting backup infrastructure and restricting access with a new Privileged Access Management system. This safeguards backup systems in the event that the main systems become compromised.

32. Installation of new vulnerability management software, which provides automated scanning and reporting of cybersecurity vulnerabilities on the Company's network.

33. takeCHARGE partnered with four local associations to deliver a webinar series raising awareness of electric vehicles ("EVs"). Over 80 members from Hospitality Newfoundland and Labrador, the NL Construction Association, the NL Environmental Industry Association and the Canadian Home Builders' Association NL tuned in to get up to speed on EVs in the province.

34. Implementation of an upgrade to cloud based Itron Mobile technology to read meters was completed. Each meter reading vehicle can read up to 100,000 meters in one day and return the information remotely from the field. This technology innovation allows Newfoundland Power to collect more data at a faster rate, improves operating efficiencies, and provides better service to customers by reducing meter reading estimates and the need to access customer properties.

35. A project was launched to study the potential distribution system impacts from increased EV load, in partnership with software vendor Opus One Solutions.

36. The 10th annual takeCHARGE of your Town Challenge received 40 proposals from municipalities across the province on ways to make their communities more energy efficient.

37. A new e-recruitment and on-boarding module for its VIP human resources management system was implemented. This module provides a collaborative workspace for recruiting, with increased transparency and communication for the hiring manager. It also centralizes all related documentation and approvals and provides initial screening to more easily identify a short list of the top applicants.

38. Inclusive Leader training was delivered to all of the Company's 93 managers and supervisors, in partnership with the Women In Resource Development Corporation ("WRDC"). Topics included elements of diversity and unconscious bias. Over 85% of non-supervisory employees have also participated in Inclusion and Diversity ("I&D") awareness sessions delivered online and in-person.

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 2019	Actual 2020	Actual 2021	Plan 2021	Measure Achieved
Reliability	Outage Hours/Customer (SAIDI) – excluding Hydro loss of supply[1]	2.34	2.98	2.48	2.50	Yes
	Outage/Customer (SAIFI) – excluding Hydro loss of supply[1]	1.62	2.35	1.96	1.73	No
	Plant Availability (%)	95.7	96.8	96.0	95.0	Yes
Customer Satisfaction	% of Satisfied Customers as measured by Customer Satisfaction Survey	85.8	87.6	88.3	86.3	Yes
	Call Centre Service Level (% per second)[2]	77/60	81/60	81/60	80/60	Yes
	Trouble Call Responded to Within 2 Hours (%)	81.0	80.0	86.0	85.0	Yes
Safety	All Injury/Illness Frequency Rate	0.4	0.7	0.6	0.7	Yes
Financial	Earnings (millions)[3]	$42.3	$43.2	$43.8	$43.5	Yes
	Gross Operating Cost/Customer[4]	$229	$235	$233	$241	Yes

[1] 2019 statistics exclude the impact of a wind storm in February, Hurricane Dorian in September and a snow storm in November. 2020 statistics exclude a January storm and Snowmageddon. 2021 statistics exclude a January storm, Hurricane Larry, and a December storm.
[2] Service level is based on calls answered in 60 seconds.
[3] Earnings applicable to common shares.
[4] Excluding conservation program costs, employee future benefit costs, and non-regulated expenses.

The following table compares whether the Company measures were achieved during the 2019, 2020, and 2021 years:

Category	Measure	Measure Achieved 2019	Measure Achieved 2020	Measure Achieved 2021
Reliability	Outage Hours/Customer (SAIDI) – excluding Hydro loss of supply	Yes	No	Yes
	Outage/Customer (SAIFI) – excluding Hydro loss of supply	Yes	No	No
	Plant Availability (%)	Yes	Yes	Yes
Customer Satisfaction	% of Satisfied Customers as measured by Customer Satisfaction Survey	Yes	Yes	Yes
	Call Centre Service Level (% per second)	No	Yes	Yes
	Trouble Call Responded to Within 2 Hours (%)	No	No	Yes
Safety	All Injury/Illness Frequency Rate	Yes	Yes	Yes
Financial	Earnings (millions)	Yes	Yes	Yes
	Gross Operating Cost/Customer	Yes	Yes	Yes